EISA SECTION 526: IMPACTS ON DESC SUPPLY

REPORT DES86T1

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LMI

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Executive Summary

Section 526 of the Energy Independence and Security Act of 2007 (EISA) limits federal agencies with respect to the purchase of petroleum products derived from unconventional or alternative fuel sources whose life-cycle greenhouse gas emissions exceed those from conventional crude oil. Petroleum products derived from oil sands crude are estimated to have life-cycle emissions exceeding those from conventional oil and under some interpretations of section 526, might be significantly restricted from government purchase.

The Defense Energy Support Center (DESC) is the principal purchaser of petroleum products for the U.S. military. DESC wants to examine the impacts of section 526 on its domestic bulk purchases of military fuels, specifically those that might be derived from Canadian oil sands recovered crude (COSRC).

We find that section 526 is not completely clear concerning what is covered nor the amounts involved. One interpretation is that the Department of Defense is only constrained from *specifically contracting for* products produced from oil sands crude. Another is that products supplied to DESC cannot be *predominantly produced from* oil sands crude. And a third is that products supplied to DESC can contain only *incidental amounts* of oil sands crude, DESC's bulk fuel purchases of fuels will be importantly affected by which of these interpretations governs.

Refiners invest in certain types of processing equipment to handle large quantities of heavy crudes such as those from oil sands. Generally, refiners who process such crudes in significant quantities have catalytic hydrocracking or coking (CorC) capabilities. In this study, we examine which of DESC's suppliers possessed such equipment in FY03–06 and which are planning to add it over the next few years.

Taking into account CorC processing capability plus access to pipelines, published reports, and private communications, we could identify only four DESC suppliers that definitely have been processing COSRC. However, using the same sources of information, we identified 15 others as probable or uncertain with respect to COSRC use, so that as many as 19 may already have been processing it.

In the near future, up to 21 DESC suppliers may use COSRC, and 6 of them are openly planning to do so.

We also sought to quantify how much COSRC each DESC supplier *potentially* could have processed. Using ownership of CorC equipment as a proxy for processing capacity for oil sands crude and imports of COSRC to each Petroleum Administration for Defense District, we provide estimates of the amounts potentially used by DESC suppliers in 2006 as a proportion of their refining capacity. By these estimates, only six suppliers potentially could have processed more than 2 percent COSRC in that year. Five more potentially could have processed between 1 and 2 percent and another 12, less than 1 percent. These numbers do not exactly accord with the numbers reported above because some refiners with heavy oil processing capacity are understood not to have been processing COSRC at the time.

If DESC is forced to purchase bulk oil product containing only minimal quantities of COSRC, it may have to require some of its suppliers to isolate non-COSRC oil and product refined from it. This will likely result in fewer suppliers than otherwise and increased costs of supply to DESC. However, we did not investigate how refiners would comply with this type of requirement nor what the incremental costs to DESC would be.

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Chapter 1
Introduction

Section 526 of the Energy Independence and Security Act of 2007 (EISA) forbids federal agencies from purchasing petroleum products derived from unconventional or alternative fuel sources whose life-cycle greenhouse gas (GHG) emissions exceed those of conventional crude oil, except as part of a research program.

The Defense Energy Support Center (DESC) is the principal purchaser of petroleum products for the U.S. military. DESC is concerned that petroleum products derived from oil sands crude are estimated to have life-cycle emissions exceeding those from conventional oil and, under some interpretations of section 526, would be significantly restricted from government purchase. DESC asked LMI to assess the impact of section 526 on its domestic bulk purchases of military fuels.

This report provides such an assessment, focusing mainly on oil products derived from Canadian oil sands, the principal unconventional source of crude oil supplied to the United States. We also briefly examine Venezuelan-supplied extra heavy oil and Fischer Tropsch (F-T)-derived fuels. The latter are discussed in Appendix A.

The report is organized as follows:

- In Chapter 2, we review section 526 of EISA and a series of ensuing letters from members of Congress that seek to clarify its content.
- In Chapter 3, we briefly discuss DESC's domestic bulk fuel operations, the U.S. refining industry, and the principal sources of crude oil for that industry.
- In Chapter 4, we review the Canadian oil sands industry, its present status, and its plans for growth over the next several years. We suggest that if these plans are realized, Canadian oil sands crude oil will be a steadily growing source of supply to U.S. refiners.
- In Chapter 5, we discuss imports of Canadian crude into the United States, focusing on the import of heavy crude oil from western Canada, where it enters the United States, and which companies purchase it. We also discuss ways in which crude oil and products within the U.S. supply system tend to be mixed together throughout the various processing steps.
- In Chapter 6, we examine DESC's bulk fuel purchases in FY03–06, characterized by Petroleum Administration for Defense District (PADD). The data indicate which refineries in each PADD are the principal suppliers of fuel to DESC.

We then assess which of them have the capability to process Canadian oil sands recovered crude (COSRC) or have plans to acquire such capability. This helps to identify companies in a position to process large quantities of oil sands crude and those unable to process more than token amounts. We examine, by PADD, which of the refineries are processing oil sands crude and which plan to do so.

We also examine the destination of COSRC exports to the United States, by PADD. From that information, data on catalytic hydrocracking or coking (CorC), and total refining capacity by PADD, we estimate the average amount of COSRC per unit of capacity, by PADD. We then break these data down to the individual refinery level and estimate the potential capability to process COSRC relative to refinery capacity for each DESC supplier.

- In Chapter 7, we discuss implications of our results for DESC domestic bulk purchase operations.
- In Chapter 8, we offer our conclusions.
- In the appendix, we discuss Venezuelan-supplied extra heavy oil and F-T-derived fuels.

Chapter 2
EISA Section 526

EISA was enacted on December 19, 2007. Section 526 of this law, which pertains to U.S. government purchases of alternative fuels, states the following:

> No Federal agency shall enter into a contract for procurement of an alternative or synthetic fuel, including a fuel produced from nonconventional petroleum sources, for any mobility-related use, other than for research or testing, unless the contract specifies that the lifecycle greenhouse gas emissions associated with the production and combustion of the fuel supplied under the contract must, on an ongoing basis, be less than or equal to such emissions from the equivalent conventional fuel produced from conventional petroleum sources.[1]

In other words, the Department of Defense (DoD) is restricted from purchasing mobility-related fuels from unconventional or alternate fuel sources with life-cycle GHG emissions above those derived from conventional petroleum, except for research and testing purposes.

Following enactment of EISA, a series of letters written by Congressmen sought to clarify the provision. In January 2008, Congressmen Henry Waxman (D-CA) and Tom Davis (R-VA) wrote to Secretary of Defense Robert M. Gates requesting information on how DoD planned to comply with the legislation. The letter specifically referred to fuel derived from oil sands:

> Explain how the Department will comply with section 526 with respect to fuel that is derived from tar sands or other unconventional petroleum sources, but is purchased under a contract that does not specify the source of the fuel. In particular, describe how the Department will ensure that fuel supply contracts are drafted so as to exclude the provision of such fuels if they have higher greenhouse gas emissions than conventional fuel.[2]

In March 2008, Congressman Waxman wrote to Senator Jeff Bingaman, the chairman of the Senate Energy Committee, to further clarify it:

> Section 526 applies specifically to contracts to purchase fuels, and it must be interpreted in a manner that makes sense in light of federal contracting practices. The purpose of the provision is to bar federal agencies from spending taxpayer dollars to support the development and expansion of alternative fuels and fuels from unconventional sources, if those

[1] *Energy Independence and Security Act*, Public Law 110-140, December 19, 2007.

[2] Letter, from Congressmen Henry A. Waxman and Tom Davis, House Committee on Oversight and Government Reform, to the Honorable Robert M. Gates, January 30, 2008.

> fuels have higher lifecycle greenhouse gas emissions than the comparable conventional fuels. It was not intended to bar federal agencies from entering into contracts to purchase fuels that are generally available in the market, such as diesel or jet fuel, that may contain incidental amounts of fuel produced from nonconventional petroleum sources.
>
> Thus, section 526 would clearly apply to a contract that specifically requires the contractor to provide an alternative fuel, such as coal-to-liquids fuel, or a fuel produced from a nonconventional petroleum source, such as fuel from tar sands. The provision also would apply to such a contract where the purpose of the contract is to obtain such an alternative fuel or fuel from a nonconventional petroleum source, even if the source of the fuel is not explicitly identified in the contract. Similarly, a contract that supports or provides incentives for a refinery upgrade or expansion to allow a refinery to use or increase its use of tar sands oils would also be subject to section 526. This provision would not apply to contracts to purchase a generally available fuel, such as a specific diesel or jet fuel blend, if that fuel is not an alternative fuel or predominantly produced from an unconventional fuel source. [3]

Congressman Waxman wrote another letter, this time to Senators Carl Levin (D-MI) and John McCain (R-AZ), in their respective positions as chairman and ranking minority member of the Senate Armed Services Committee. The letter discussed the legislative history of the provision and then articulated once again how section 526 applies to oil sands:

> With respect to tar sands, section 526 does not bar federal agencies from purchasing generally available fuels that may contain incidental amounts of fuel from tar sands. The provision would block a federal agency from using government contracts specifically to promote or expand the use of fuel from tar sands. I am not aware of any agency seeking to use its contract authority in this manner. [4]

The various letters from Congressmen Waxman and Davis are intended to clarify the intent of section 526. However, several terms used in the letters are not precisely defined so that the exact interpretation of Section 526 remains unclear.

[3] Letter, from Congressman Henry Waxman, Chairman, Committee on Oversight and Government Reform, to Senator Jeff Bingaman, March 17, 2008.

[4] Letter, from Congressman Henry Waxman to Senators Carl Levin and John McCain, May 2, 2008.

Chapter 3
DESC Sources of Supply

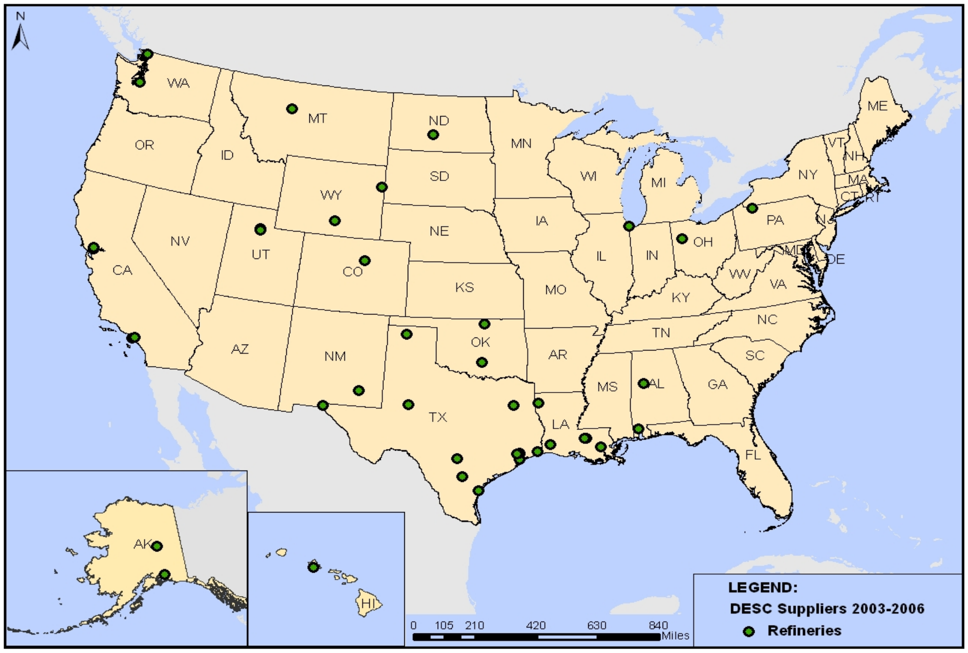
The constraints imposed by section 526 apply to all U.S. government purchases of fuels. However, DoD is by far the largest government buyer of these fuels, and DESC is the principal purchaser of these fuels on behalf of the U.S. military. Thus, interaction between DESC and its fuel suppliers will largely determine how the provision is implemented.

DESC operates worldwide, supplying military specification petroleum products such as jet, diesel, and maritime fuels to installations and active operations. Domestic requirements are usually purchased from suppliers based in the United States, while overseas requirements are usually obtained from foreign sources. Contracts with suppliers are generally negotiated.

The principal U.S. suppliers to DESC are domestic refining companies, which are located throughout the country and include a number of smaller companies as well as some very large ones. In any given year, the bulk of DESC's purchases are made from about 20 refiners, some of which own multiple refineries and supply DESC from more than one. Others own a single refinery, but it may be strategically located near one or more military installations and hence provide a key source of supply. The locations of DESC's suppliers between FY03 and FY06 are shown in Figure 3-1.

Most fuel purchased domestically is supplied to U.S. installations, where it is principally used in the training process. However, some is supplied to ships for use at sea and to military aircraft headed elsewhere. A small part is used at installations for heating purposes. Also, DESC purchases limited quantities of bulk lubricating oils and bulk fuel additives, as well as packaged versions of both.

Figure 3-1. DESC Supplying Refineries, 2003–2006*



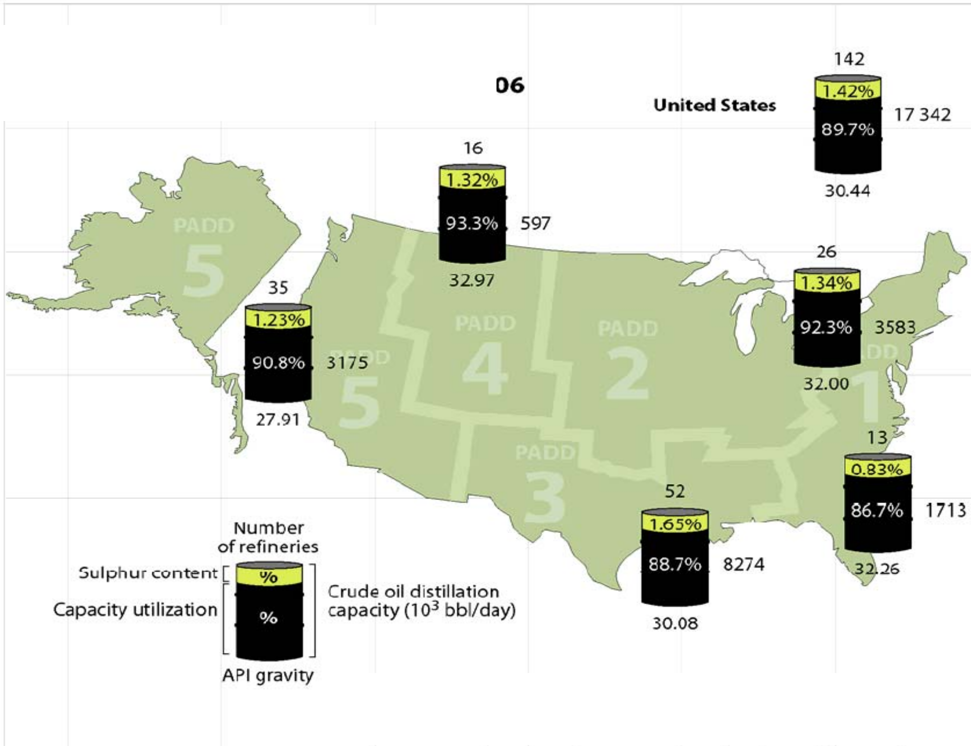
Source: Monica DeAngelo, LMI GIS. DESC Supplying Refineries 2003–2006* [map]. 1:33,000,000, USA Contiguous Albers Equal Area Conic, NAD83. *Internal database for DES86.02 (DESC_refineries.dbf) [computer file]*. McLean, VA: October 2008. Using ArcView GIS Version 9.3. Redlands, CA: Environmental Systems Research Institute, Inc, 2008.

U.S. Refining Industry

The U.S. Department of Energy (DOE) lists 143 active refineries in the United States, ranging in size from 2,000 barrels per day (b/d) of capacity to refine crude oil into product to 567,000 b/d. In all, refining industry capacity in the United States totals about 17½ million b/d. Figure 3-2 shows U.S. refineries by PADD as of 2006 (it does not show the two refineries situated in Hawaii). The diagram also shows the average American Petroleum Institute (API) gravity of oil refined by PADD,[1] sulfur content, and refinery capacity.

[1] API gravity refers to an inverse measure of the weight of crude oil, relative to water. A low API gravity denotes a heavy oil, a high one a light oil. The term will be used in the context of COSRC later in the report.

Figure 3-2. U.S. Operating Refineries by PADD, 2006



Source: Energy Information Administration (EIA).

A number of foreign refineries also supply the United States, including several in the Caribbean Islands. For example, the Venezuelan national oil company PDVSA leases a 320,000 b/d refinery in Curacao which exports petroleum products to the United States and elsewhere. Petroleum product also is supplied to the United States from Europe and Asia.

The basic refining process involves breaking down crude oil into a variety of products. Refineries contain processing units that use heat, pressure, catalysts, and gases to cleanse crude oil of various impurities and transform its molecules, producing a slate of liquids and solids, including petrochemical products, which then are transported to markets. Refineries are configured in different ways, some specializing in the production of gasoline, others in middle distillates such as diesel and jet fuel, and a few in heavier products such as asphalt. The various configurations involve different types of equipment. Basic distillation units break crude oil down into fractional parts, but its refinement into products involves catalytic cracking, catalytic hydrocracking, coking, desulfurization and desalting, hydrotreating, alkylation, and other processes.

Crude oils fashioned from oil sands tend to be low in gravity and unusually viscous. Refineries upgrade this type of oil through the use of catalytic hydrocracking, which adds hydrogen and strips carbon from the heavy oil, and the use of coking units, which thermally crack the long chain molecules contained in

heavy oil and transform them into shorter chains as well as petroleum coke. Through these processes, refiners are able to produce distillates, gasoline, and jet fuel from such oil. As the mix of crudes has gradually shifted toward heavier grades, refiners have invested more heavily in hydrocracking and coking units, each of which can cost several hundreds of millions of dollars for a single large refinery.

A few refineries are able to process heavy crude by producing comparatively large quantities of asphalt and by processing diluents mixed with such oils into lighter products. Further, most refineries can process small amounts of this oil as part of a larger mix consisting mostly of lighter crudes. However, if a refinery is to process significant amounts of heavy crude oil into middle distillates, gasoline, and jet fuel, the types of products sold to DESC, it generally must have CorC capability.[2] From this fact, we later separate DESC suppliers capable of refining significant quantities of COSRC from those without this capability.

U.S. Crude Oil Supply

The United States consumes approximately 20 million b/d of petroleum products. Domestic crude oil production is about 7 million b/d, or 35 percent of the total. Another 10 million b/d or so of crude oil is imported, so U.S. refineries process about 17 million b/d for domestic consumption. The other 3 million b/d of consumption comes from U.S. petroleum product imports.

The principal exporters of crude oil to the United States are Canada, Saudi Arabia, Mexico, Nigeria, and Venezuela. Table 3-1 shows the top eight exporters of crude oil into the United States in the first half of 2008.

Table 3-1. Principal Sources of U.S. Crude Oil Imports—First 6 months of 2008

Country	Exports to United States (000 b/d)
Canada	1,888
Saudi Arabia	1,523
Mexico	1,193
Nigeria	1,036
Venezuela	1,012
Iraq	674
Angola	496
Algeria	319

[2] Personal communications with Jennifer Holmgren, UOP LLC, and Ronald Jones, vice president, API (ret.), September 2008.

U.S. HEAVY OIL IMPORTS

Total U.S. crude oil imports in 2007 were around 10 million b/d. The percentage made up of heavy oil depends upon the definition of that term. Heavy oil is variously defined, sometimes as oil below 20 degrees API gravity, but also by the petroleum industry as oil below 22.3 degrees API.

The U.S. imports heavy oil from at least three sources; Canada, Mexico, and Venezuela. In the case of Canada, heavy oil imports include but are not exclusively made up of COSRC. These are about 1 million b/d. Mexico exported 1.4 million b/d to the U.S. in 2007. About 2/3 of the country's crude exports are of Mayan heavy crude, with an API gravity of 19-22 degrees. This is probably a good approximation of the proportion of Mexican heavy oil exported to the U.S. Venezuela produces an extra heavy crude oil defined as API gravity of 10 or less. In 2007 it exported 600,000 b/d of this crude, but the proportion sent to the U.S. is not available. Several Gulf Coast refineries have capability to refine this oil, however.

EIA provides monthly data on the percentage of U.S. crude oil imports that are 20 degrees API or less. This category would include COSRC and Venezuelan extra heavy crude. In 2007 the monthly average was 11.7 percent. This implies 1.2 million b/d of crude oil imports below 20 degrees API gravity. The percentage of this category of heavy crude in U.S. imports has been slowly rising over the years. In 2000, for example, the monthly average was 6.2 percent.

EIA also supplies data on imports of crude oil between 20.1 degrees and 25 degrees API. For 2007, the monthly average in this category was 23.1 percent. If we assume a linear relationship between API degrees and percentage imports, then another 10.6 percent of U.S. crude imports would have been between 20 and 22.3 degrees API. ($2.3/5 \times 23.1$) Combining this figure with the 11.7 percent above, 22.3 percent or 2.3 million b/d of U.S. crude oil imports in 2007 were heavy oil by the industry's definition of the term. This would include Mexican Maya crude as well as COSRC and Venezuelan extra heavy crude.

Chapter 4
COSRC Supply and Availability

The main deposits of Canadian oil sands are located in Athabasca, Peace River, and Cold Lake in the province of Alberta. According to the Alberta Department of Energy, the province's oil sands contained more than 1.7 trillion barrels of oil as of 2007. However, only a small portion—around 10 percent—are considered proved reserves. Still, these reserves, 173 billion barrels, would constitute the second largest oil reserves in the world (behind those of Saudi Arabia).[1]

Proved reserves are those that can be recovered with present technology and under existing economic conditions. In general, the technology of oil sands extraction can be expected to improve with time, so that even as oil is extracted, new reserves will be added. Because of this, the proved reserve estimate understates what will be ultimately recovered. The Alberta Energy Resources and Conservation Board estimates the ultimately recoverable resource base at 315 billion barrels.

Smaller deposits exist in Saskatchewan, near the Alberta Athabasca oil sands deposit. The Saskatchewan Ministry of Energy and Resources estimates that there are 7.3 million acres of potential oil sands bearing land in the province, but the resource base on that land has not been officially determined. Should Saskatchewan oil sands prove economic, additional pipeline infrastructure would be necessary to bring the resulting product to market.

About 20 percent of proved oil sands reserves in Alberta can be recovered by surface mining. This technology works best where the overburden (the material on top of the oil sands) is less than 75 meters in depth. The remaining 80 percent of the oil sands in Alberta are buried at depths of greater than 75 meters, where recovery is generally done through the use of in situ (in place) technologies.

SURFACE MINING

In surface mining, truck-and-shovel operations pull away the overburden and extract the sands themselves. Some of the world's largest trucks are used, the Caterpillar 797 and 797B, with payloads of 380 tons. The mined oil sands contain anywhere from 1 to 20 percent bitumen, with the rest composed of clay, sand, and

[1] In its International Energy Outlook (IEO), the DOE includes these reserves as conventional crude oil. It cites the Canadian Association of Petroleum Producers for this classification. The *Oil and Gas Journal* also classifies these reserves as conventional oil ("Worldwide Look at Reserves and Production," 100, No. 52, December 23, 2002.) However, other sources such as the *BP Statistical Review of World Energy* do not include Canadian oil sands in their country crude oil reserve estimates.

other sediments and minerals. Once the sands are mined, the bitumen is separated from the other materials through a four-step process: conditioning, separation, secondary separation, and froth treatment.

Hot water and caustic soda is added to the sand, and the resulting slurry piped to an extraction plant where it is agitated and the oil skimmed from the top. Provided that the water chemistry is appropriate to allow bitumen to separate from sand and clay, the combination of hot water and agitation releases bitumen from the tar sand and allows small air bubbles to attach to the bitumen droplets. The bitumen froth floats to the top of separation vessels, and is further treated to remove residual water and fine solids.

Recent enhancements to the separation process include tailings oil recovery units, which recover oil from the tailings, diluent recovery units to recover naptha from the froth, inclined plate settlers, and disc centrifuges. These allow the extraction plants to recover more than 90 percent of the bitumen in the sand.

The bitumen is then transported and eventually upgraded into synthetic crude oil. About 2 tons of tar sands are required to produce one barrel (approximately 1/8 of a ton) of oil. After oil extraction, the spent sand and other materials are returned to the mine, which is eventually reclaimed.

IN SITU PROCESSES

Mining generally is less costly than in situ production and hence has been the technology of choice for the majority of COSRC extraction to date. In 2007, the last year for which full data are available, about 55 percent of oil sands were extracted via this technology and 45 percent through in situ methods. Four types of in situ methods are in use:

- *Steam-assisted gravity drainage*. This is the most commonly used approach. Two parallel horizontal wells are drilled through the oil-bearing formation, and steam is injected into the upper well, creating a high-temperature steam chamber. The increased heat loosens the thick crude oil, causing it to flow downward in the reservoir to the second horizontal well, which is located parallel to and below the steam injection well. This heated, thinner oil then pumps to the surface via the second horizontal, or production, well. Water fills the bitumen-drained area to maintain the stability of the deposit. Up to 60 percent of the oil can be recovered using this method.

- *Cyclic steam stimulation*. High-pressure, high-temperature (about 350°C) steam is injected into oil sand deposits. The pressure of the steam fractures the oil sand, while the heat of the steam melts the bitumen. As the steam soaks into the deposit, the heated bitumen flows to a producing well, where it is pumped to the surface. The process can be applied several times in a formation, and it can take between 120 days and 2 years to

complete a steam stimulation cycle. The method is capable of recovering 20–25 percent of the oil in place. It is commonly used to extract heavy oil from the Kern River formation in California.

- *Toe-to-heel air injection*. Air or oxygen is injected into a vertical well with the hot fluid produced from a horizontal well. The combustion front moves out from the vertical well, and the hot fluids move down, by gravity, to the horizontal well. This eliminates the need to move the heated fluids through the cold bitumen, so toe-to-heel air injection can be an initiating process. In general, it uses less water and natural gas and results in a better crude product, requiring less upgrading.

- *Vapor recovery extraction*. Vapor recovery extraction uses much the same process as steam-assisted gravity drainage, but solvent is used instead of steam. This lowers the energy cost, though the additional solvent adds to the expense. The process is considered promising but has yet to be field tested.

UPGRADING

Oil sands bitumen must be upgraded before it can be shipped to refineries for processing into finished products. Bitumen is a complex hydrocarbon made up of a long chain of molecules, which generally must be broken up and reorganized. Unlike smaller hydrocarbon molecules, bitumen is carbon rich and hydrogen poor. Upgrading means removing some carbon while adding hydrogen to make more valuable hydrocarbon products. This is done using four main processes:

- Thermal conversion or coking, which removes carbon and breaks large bitumen molecules into smaller parts

- Distillation, which sorts mixtures of hydrocarbon molecules into their components

- Catalytic conversion, which helps transform hydrocarbons into more valuable forms

- Hydrotreating, which is used to help remove sulphur and nitrogen and add hydrogen to molecules.

The end product is synthetic crude oil, which is shipped by pipeline to refineries across North America to be refined further into jet fuels, gasoline, and other petroleum products.

Four upgraders are operating in Edmonton, the processing hub of Alberta. Plans exist to triple upgrading capacity in the area over the next 15 years.

Alberta's three main upgrading companies produce a variety of synthetic products. Suncor Energy produces light sweet and medium sour crudes plus diesel, Syncrude produces light sweet synthetic crude, and Shell produces intermediate refinery feedstock for the Shell Scotford Refinery, as well as sweet and heavy synthetic crude.[2] Production from new upgraders is expected to align with refinery product requirements.

Although most bitumen is upgraded in Alberta, it also can be shipped by pipeline, if diluted sufficiently with lighter oils, for upgrading at refineries located elsewhere. Diluents include light sweet crude oil or natural gas liquids. The latter is easily separated at refineries once the mixture arrives. Generally, mined bitumen is upgraded, while much of the oil sands crude produced through in situ methods is shipped with diluent.

PRODUCTION

To Date

Suncor initiated the first Canadian oil sands mining venture in 1967.[3] In 1978, a consortium of companies named Syncrude began a second mining venture. However, because of the costs of oil sands mining and uncertain prospects for crude oil prices, it took until 2003 for Shell Canada to begin production from a third venture, the Albian Sands mine.

Over the past several years, as crude prices have risen, oil sands production has increased. Data for Canadian oil sands production is broken down into two categories: that from mining and that from in situ extraction. Table 4-1 gives production data for both categories from 1999 through 2007.

Table 4-1. Historical Oil Sands Production (thousands of b/d)

Type	1999	2000	2001	2002	2003	2004	2005	2006	2007
Mining	324	320	349	441	513	601	536	631	666
In situ	244	289	310	303	349	384	439	494	536
Total	568	609	659	744	862	985	975	1,125	1,202

Over the 8 years ending in 2007, production more than doubled, from less than 600,000 b/d to more than 1.2 million b/d. The annual rate of growth over the period was around 10 percent, stimulated in large part by the rapid rise in crude oil prices over the past few years.

[2] "Sweet" crude oil is low in sulfur content, generally below 0.5 percent, whereas "sour" crude contains a greater relative proportion.

[3] At the time, the company was called Great Canadian Oil Sands, Ltd., and was a subsidiary of Sun Oil Company.

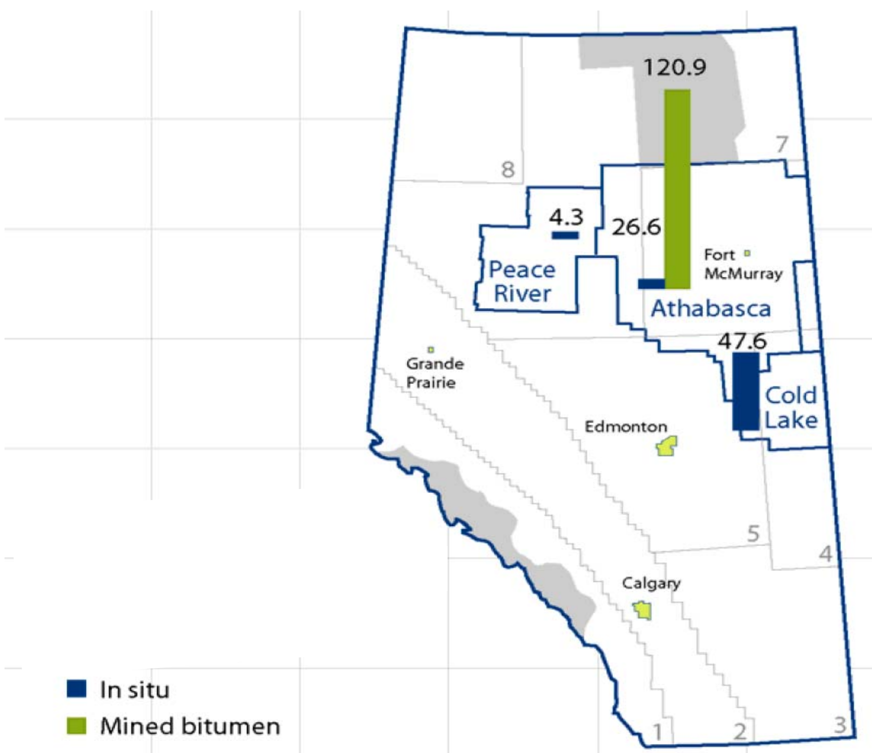
Canadian oil sands reserves also increased over the period. Table 4-2 shows these reserves as of year end 1999 through 2006. According to the data in the table, these reserves roughly doubled between 1999 and 2006.

Table 4-2. Canadian Oil Sands Reserves (millions of barrels as of year end)

Type	1999	2000	2001	2002	2003	2004	2005	2006
Mining	5,034	5,011	4.919	4.881	5,213	5,294	6,125	8,871
In situ	1,561	1,805	1,820	2,024	2,032	2,082	2,474	4,706
Total	6,595	6,816	6,739	6,905	7,245	7,376	8,599	13,577

Figure 4-1 shows where COSRC is mined and where it is produced through in situ methods. The great majority of Athabasca sands are mined, while production at Cold Lake and Peace River is obtained from in situ methods.

Figure 4-1. Production of Bitumen in Alberta, Canada, 2006



Expansion

A number of firms have announced plans to enter the oil sands production business or to expand existing production. Table 4-3, summarizing a report issued by Strategy West, Inc., shows the number of oil sands projects already underway and the numbers planned over the next several years. The table also lists the number of planned and existing upgrading projects.

Because not all the planned projects will necessarily unfold as announced, the numbers are more indicative than definitive. Nevertheless, they indicate that production and upgrading likely will substantially expand Canadian oil sands production over the next decade or so.

Table 4-3. Number of Existing and Planned Canadian Oil Sands Projects

Project type	In operation	Planned
Athabasca mining	3	9
Athabasca in situ	9	20
Cold Lake in situ	3	2
Peace River in situ	1	1
Upgraders	4	12

Source: Strategy West, Inc., *Existing and Proposed Canadian Commercial Oil Sands Projects*, April 2008.

Forecast

The Canadian Association of Petroleum Producers (CAPP) publishes annual forecasts of future Canadian crude oil production. Its most recent forecast distinguishes oil sands from other Canadian oil production and breaks it down between mined and in situ production. Table 4-4 shows CAPP's "moderate growth" case for 2008–10 and selected years through 2020.

Table 4-4. Projected Oil Sands Production (thousands of b/d)

Type	2008	2009	2010	2012	2015	2017	2020
Mined	701	814	838	1,043	1,467	1,649	1,961
In situ	608	712	781	973	1,302	1,403	1,578
Total	1,309	1,526	1,619	2,016	2,769	3,052	3,539

Under CAPP's projections, oil sands production would more than double within the next 7 years, by 2015, though the rate of growth would slow from there. According to the projection, by 2020 Canadian oil sands production would be nearly three times what it is today.[4] If most of this oil were shipped to the United States and this country continued to consume about 20 mbpd, COSRC would represent about 15 percent of total U.S. supply.

[4] CAPP also issues a "pipeline planning" case, which suggests an even more rapid increase in oil sands production, to 4.5 million barrels per day (mbpd) by 2020.

MARKETS

The principal markets for western Canadian crude oil and oil sands–derived oil are within Canada itself and the United States. Pipelines carry that oil to the west, east, and south; destinations in Puget Sound and Washington state; Wyoming, Oklahoma, and Texas; and Illinois, Ontario, and Quebec.

In addition, a small amount of western Canadian oil is shipped to Asian markets, which have expanded greatly in recent years. Asian companies have become involved in Canadian oil sands and are active in development there. For example, the China National Petroleum Company purchased exploration rights to 11 sections in Alberta in 2007 (about 100 square miles), and the China National Offshore Oil Corporation and Sinopec, the largest Chinese refiner, have substantial ownership interests in oil sands production ventures in Alberta. About 21,300 b/d of Western Canadian crude production was shipped to Asia in 2007.[5]

PIPELINES

Oil sands product is shipped from the principal producing areas by pipeline, by far the most economical method of transport. Several lines move this oil to refineries throughout Canada and the United States, and many more are planned. The lines also are used to ship conventional crude oil out of Alberta, but this production has been declining while oil sands production has been rising, so most of the expansion is directed at moving COSRC to markets.

Canadian producers of oil sands are paid on a netback basis, which considers the value of products produced from the oil less transport costs. From the producer perspective, the greater their access to markets (that is, the more refineries they can reach), the higher this netback is likely to be. Therefore, producers have a direct economic interest in seeing more pipelines to move COSRC to refineries and in expanding capacity on existing lines. Specifically, they are interested in greater capacity to move COSRC to major U.S. refinery centers such as the Texas Gulf Coast, where aggregate capacity is about 5.6 million b/d. Recent declines in Venezuelan and Mexican heavy crude oil production offers an opportunity for COSRC in that market.

Current Distribution

More than 70 percent of western Canadian crude oil (both conventional and COSRC) presently is delivered to refineries or to other pipelines by three major trunk pipeline systems—the Enbridge system and Kinder Morgan's Trans Mountain and Express pipelines. Table 4-5 shows the estimated capacity of the three.

[5] Canadian Association of Petroleum Producers, op cit. p. 14.

Table 4-5. Estimated Capacity of Major Canadian Trunk Lines

Pipeline	Crude quality	Estimated capacity (thousand b/d)
Enbridge	Light Heavy	580 1,153
Express	Light/heavy (35/65)	282
Trans Mountain	Light/heavy (80/20)	285
Total	—	2,300

Source: CAPP, *Crude Oil Forecast, Markets & Pipeline Expansions*, June 2008.

The Enbridge line, the world's longest crude oil pipeline, is the principal route to the east from Alberta. Enbridge Pipelines, Inc., owns the portion of Enbridge that starts in Edmonton and ends in Gretna, Manitoba. When the Enbridge line enters the United States in North Dakota, it comes under the ownership of Enbridge Energy Partnership, L.P. This U.S. portion is the Lakehead pipeline, which has junction points at Clearbrook, MN; Superior, MI; Lockport, IL; and Chicago, IL, before heading northeast through Wisconsin to Sarnia, Ontario, northeast of Detroit, MI.

In addition, Enbridge jointly owns with ExxonMobil the Mustang and Pegasus lines. Mustang connects to the Lakehead system in Lockport and ends in Patoka, IL, a major junction point for several pipelines. Pegasus goes from Patoka, IL, to Nederland, TX; it was reversed in 2006 from south to north to north to south. Nederland is located on the Gulf Coast, amidst some of the country's largest refineries. Thus, through this line, some Canadian oil sands crude can be shipped directly from Edmonton to the Gulf Coast market (Figure 4-2).

Figure 4-2. Enbridge and Connecting Pipelines from Edmonton to Gulf Coast

Source: Monica DeAngelo, LMI GIS. Enbridge and connecting pipelines from Edmonton to the Gulf Coast [map]. 1:28,000,000, USA Contiguous Albers Equal Area Conic, NAD83. *HSIP Gold 2007 Oil Pipelines and Refineries (Energy.mbd) [computer file]*. McLean, VA: October 2008. Using ArcView GIS Version 9.3. Redlands, CA: Environmental Systems Research Institute, Inc, 2008.

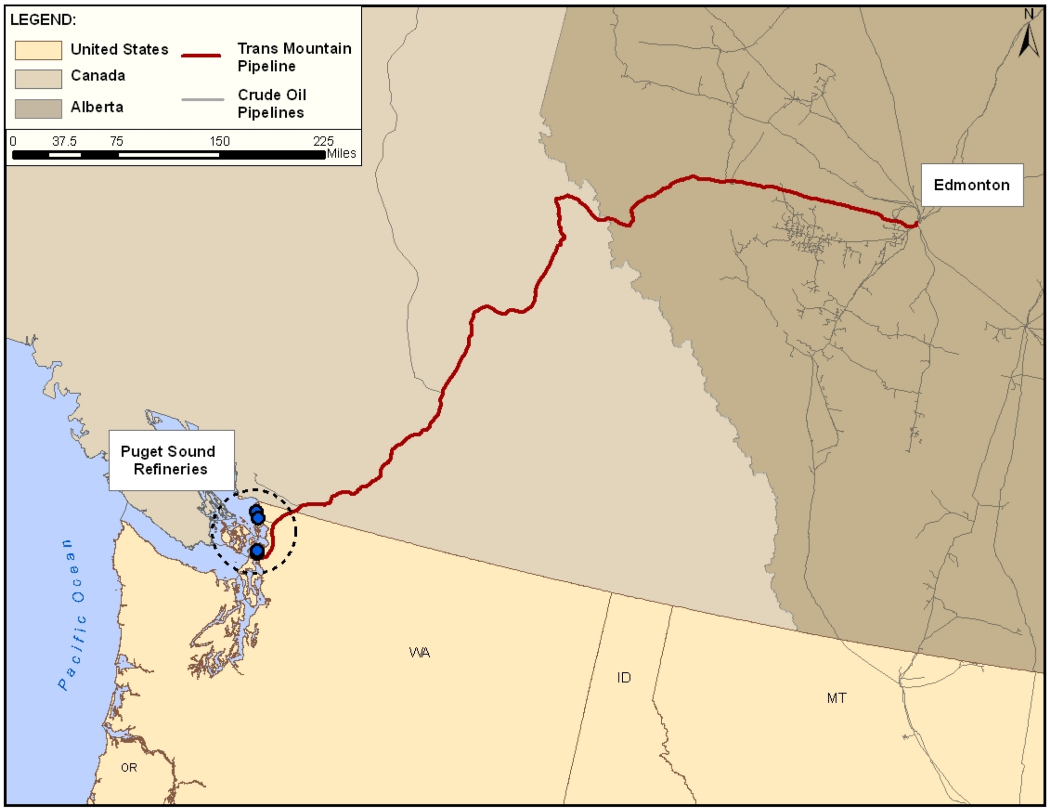
The Express pipeline ships oil south from Hardisty, Alberta, through Montana to Casper, WY, where it connects with the Platte pipeline system. Platte connects with the Jayhawk pipeline system in Nebraska, which in turn carries oil to Cushing, OK, a major junction point for U.S. crude oil pipelines. Because of its many interconnections, the Express line is capable of delivering oil through wide areas of the Midwest and Rocky Mountains and, through the Cushing interconnection, to many areas of the Southwest. Figure 4-3 shows the route from Hardisty to Cushing.

Figure 4-3. Express and Connecting Pipelines from Hardisty to Cushing

Source: Monica DeAngelo, LMI GIS. Express and connecting pipelines from Hardisty to Cushing, OK [map]. 1:21,000,000, USA Contiguous Albers Equal Area Conic, NAD83. *HSIP Gold 2007 Oil Pipelines and Refineries (Energy.mbd) [computer file]*. McLean, VA: October 2008. Using ArcView GIS Version 9.3. Redlands, CA: Environmental Systems Research Institute, Inc, 2008.

The Trans Mountain pipeline originates in Edmonton and ends in Puget Sound (Figure 4-4). This endpoint includes the Westridge dock for barge or vessel loadings. A branch of the pipeline brings crude down to refineries in Anacortes and Ferndale, WA. Crude shipped to the dock in Vancouver could go to the Far East and potentially could be shipped in quantity to California refineries. At present, only small amounts of Canadian crude oil are shipped to the California market.

Figure 4-4. Trans Mountain Pipeline Route from Edmonton to Puget Sound



Source: Monica DeAngelo, LMI GIS. Trans Mountain pipeline route from Edmonton to Puget Sound [map]. 1:8,500,000, USA Contiguous Albers Equal Area Conic, NAD83. *HSIP Gold 2007 Oil Pipelines and Refineries (Energy.mbd) [computer file]*. McLean, VA: October 2008. Using ArcView GIS Version 9.3. Redlands, CA: Environmental Systems Research Institute, Inc, 2008.

Expansion

A very large number of pipeline projects to move COSRC are underway or have been announced. Several are near term, but the greater number are longer term, over a 5- to 10-year period. Completion of all of these is unlikely because in aggregate they exceed what is likely to be needed. Nevertheless, they give a good idea of the types of projects likely to unfold.

Table 4-6 shows near-term pipeline expansion projects, just completed or due to be completed within the next 2 years, along with the capacity they represent.

Table 4-6. Near-Term Oil Sands Pipeline Expansion Projects

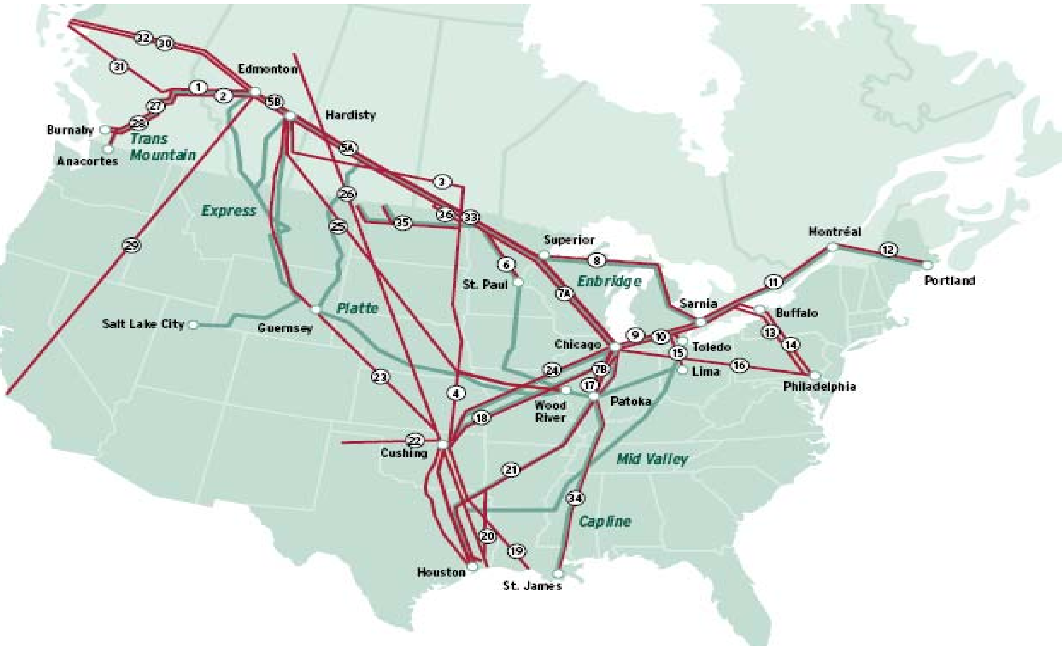
Pipeline	Proposed in-service date	Capacity (thousand b/d)
Kinder Morgan TMX1A	April 2008 (operating)	25
Kinder Morgan TMX1B	November 2008	15
TransCanada Keystone	December 2009	435
Enbridge Alberta Clipper	July 2010	450
TransCanada Keystone Extension	4Q 2010	155
Total		1,080

The two Kinder Morgan projects will increase the capacity to ship COSRC into the Vancouver area for use on the West Coast or for shipment to the Far East. They are small, however, compared with the three other expansion projects.

Trans-Canada Keystone will greatly increase pipeline capacity from Alberta into Manitoba, while the Keystone Extension will enable an additional 155,000 b/d to be shipped south from Manitoba to Cushing, OK. Enbridge Alberta Clipper will move COSRC eastward, to a connection point at Superior, WI, from which connecting lines run to Chicago, IL, and elsewhere, and will connect to the pipeline junction at Clearbrook, MN. Initial capacity will be 450,000 b/d, but according to CAPP, this could expand to 800,000 on the basis of 100 percent heavy crude oil. In aggregate, the five projects would add more than 1 mbpd of capacity.

Many other projects have been proposed, with completion farther in the future (Figure 4-5). These include a direct line from Edmonton to southern California and expanding COSRC access to Cushing and the Texas Gulf Coast. Although not all will reach fruition, they indicate that the amount of Canadian oil sands crude reaching the United States and the extent to which it will join many other crude streams at refining centers will greatly expand in the next several years.

Figure 4-5. Proposed Canadian and U.S. Crude Oil Pipelines



1	Kinder Morgan TMX1A Expansion	12	Portland Pipeline Reversal	25	TransCanada Keystone XL
2	Kinder Morgan TMX1B Expansion	13	Sunoco – to Philadelphia	26	Altex Energy
3	TransCanada Keystone	14	Enbridge Pioneer (Opt2)	27	Kinder Morgan TMX2
4	TransCanada Keystone Cushing Extension	15	Enbridge Eastern PADD II	28	Kinder Morgan TMX3
5A	Enbridge Alberta Clipper	16	Enbridge Pioneer (Opt 1)	29	TransCanada Alberta-California
5B	Enbridge Line 4 Extension	17	ExxonMobil Mustang Expansion	30	Enbridge Northern Gateway
6	Minnesota Pipeline Expansion	18	Enbridge Spearhead Expansion (N/S)	31	Kinder Morgan TMX Northern Leg
7A	Enbridge Southern Access Expansion	19	Sunoco – to US Gulf Coast	32	Enbridge Gateway Condensate Import
7B	Enbridge Southern Access Extension	20	Enbridge/ExxonMobil Texas Access	33	Enbridge Southern Lights
8	Enbridge Line 5 Expansion	21	ExxonMobil/Enbridge Pegasus Expansion	34	Capline/Chicap
9	Enbridge Line 6B Expansion	22	Centurion Pipeline Reversal	35	Enbridge North Dakota
10	Enbridge Line 6C	23	TEPPCO/Kinder Morgan Chinook - Maple Leaf	36	Enbridge Light Sour Line
11	Enbridge Line 9 Re-reversal	24	BP No. 1 Pipeline		

Source: CAPP, "Crude Oil Forecast, Markets & Pipeline Expansions," June 2008.

OTHER SOURCES

Venezuela

Venezuela is recognized as having substantial reserves of both conventional and oil sands oil. Its currently proven oil reserves total about 80 billion barrels, approximately 35 billion barrels of which are what the Venezuelans call extra-heavy (oil sands) oil. Although this amount is considerable, it is dwarfed by the potential of extra-heavy oil reserves that are not yet considered proven. As much as 1.2 (and perhaps even 1.7) trillion barrels may exist in Venezuela's Orinoco Belt (a band of oil deposited roughly beneath the Orinoco River). Estimates of recoverable reserves in this belt range from 100 billion to 270 billion barrels.

As mentioned in Chapter 3, Venezuela exports approximately 600,000 b/d of extra heavy oil. A good deal of that oil is exported to the U.S. Gulf Coast because several U.S. refineries there can handle this grade. PDVSA, Venezuela's national oil company, owns two Gulf Coast refineries outright at Corpus Christi, TX

(156,000 b/d of crude processing capacity), and Lake Charles, LA (425,000 b/d capacity). It also is part owner of a refinery in Chalmette, LA (192,760 b/d capacity). Other Venezuelan crude oil is exported to a 50 percent PDVSA-owned refinery at St. Croix in the U.S. Virgin Islands (494,000 b/d capacity) and to the PDVSA-leased Isla refinery in Curacao (320,000 b/d capacity). Crude oil delivered to the Virgin Islands refinery would be considered part of U.S. imports whereas deliveries to Curacao would not. Products from the Caribbean refineries are exported to the United States and elsewhere throughout the region.

In 2007 Venezuela exported 1.148 million b/d of crude oil to the U.S. If all Venezuelan extra heavy crude were exported to the U.S. it would have made up 52 percent of these crude exports, but the actual number probably was quite a bit lower.

Venezuelan oil production has been declining of late, in part because of domestic policy disputes and in part because of conflicts with some of its international partners. Yet, the resource base remains prodigious. Some observers believe that if Venezuela could resolve its internal and external financial and policy disputes, it could provide as much as 1.4 million b/d of extra-heavy oil to the marketplace, whether as synthetic crude oil or as bitumen mixed with diluent.

The difficulty of extracting extra-heavy oil from deep underground (Venezuela's deposits are deeper than Canada's oil sands) makes the recovery of unconventional oil more costly than in Canada. However, at recent world prices for oil, this recovery is considered economic. At the moment, Venezuela's oil development appears to depend more on the resolution of policy and financial disputes than the fundamental economics of oil recovery.

Mexico

As noted in Chapter 3, in 2007 Mexico exported 1.4 million b/d of crude oil to the U.S., of which 2/3 were Mayan heavy crude, with an API gravity of 19-22 degrees. This crude is classified as conventional production, and as such probably is not subject to Section 526. Several Gulf Coast refineries process this oil; for example, the joint PEMEX-Shell refinery at Deer Park, TX processes 240,000 b/d of Mayan crude, the Valero refinery at Port Arthur, TX processes 206,000 b/d of this crude and the Valero refinery at Texas City, TX another 170,000 b/d. However, Mexican heavy crude oil production has been declining and several Gulf Coast refiners are looking to COSRC as a substitute source of supply.

Brazil

Brazil expects to produce 15,000 b/d of extra heavy crude oil in 2008 (defined as less than 12.8 degrees API gravity). It is experimenting with methods to extract larger quantities of this grade oil in the future. At present Brazil is a slight net oil importer but production has been rising fairly rapidly and important new discoveries have been made. The U.S. is not importing Brazilian crude oil at present, but

the potential exists for extra heavy oil exports from that country, either as crude oil or as refined products.

United States

United States tar sands resources are primarily concentrated in Eastern Utah, mostly on public lands. The in-place tar sands oil resources in Utah are estimated at 12 to 19 billion barrels. There also are deposits in Alaska, Alabama, southwest Texas, California, Kentucky, Oklahoma, and Missouri, but not enough to be developed on a commercial scale.

Nevtah Capital Management and Black Sands Energy formed a joint venture to invest in Utah's tar sands, advertising a technology that purportedly uses very little water. However, Congress enacted a 1-year moratorium on oil sands or shale development in Utah in 2007, and proponents of the moratorium plan to extend it. For now, therefore, oil from domestic oil sands appears unlikely to enter the market.

Chapter 5
Canadian Crude Oil Imports

TOTAL COSRC IMPORTS FROM CANADA

According to EIA data, the U.S. imported 1.802 million b/d of crude oil from Canada in 2006. In addition, net product imports from Canada in 2006 were 392,000 b/d, so that total U.S. oil imports from that country were 2,194,000 b/d.

There are no precise numbers on U.S. imports of COSRC. We are forced to estimate this number by inference from other data. In 2006 Canada produced about 1.125 million b/d of oil sands crude, most of it (800,000 b/d) heavy oil. Much of this plus synthetic light crude was shipped to the U.S., but some remained in Canada, processed by Canadian refineries. If we use total Canadian heavy oil exports to the U.S. as a proxy for oil sands exports, we overstate oil sands-derived heavy oil exports but understate light synthetic exports. Nevertheless, it may provide a reasonable first approximation to how much COSRC was exported to the U.S. in 2006. By this method we estimate that a little over 1 million b/d of COSRC was exported in that year.

An alternative is to examine western Canadian production of unconventional heavy oil and light synthetic oil and subtract the amounts of western Canadian heavy oil and synthetic oil processed domestically. In 2006 unconventional heavy and light synthetic accounted for about 1.4 million b/d of Canadian production.[1] Refineries in western Canada processed about 400,000 b/d of western Canadian heavy and light synthetic and those in eastern Canada another 100,000 b/d. By this proxy measure Canada exported 900,000 b/d of COSRC in 2006. Because Canadian refineries processed both conventional and unconventional heavy oils from western Canada, this number probably somewhat understates COSRC exports to the U.S.

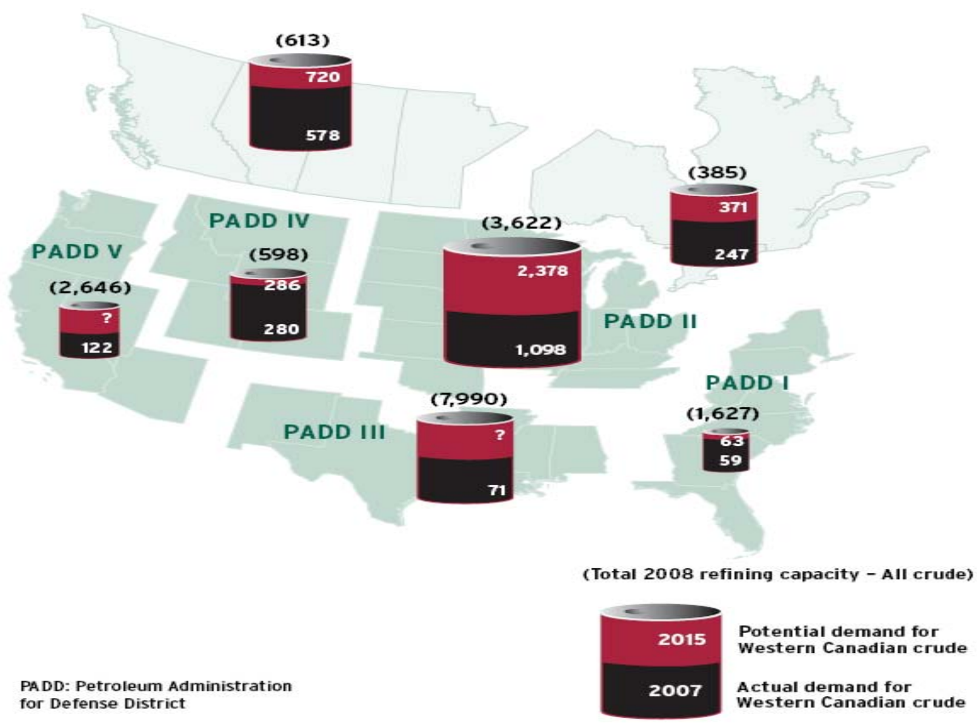
Still, the two methods provide similar estimates. But the one, heavy oil imports, is superior for our purposes in that we have data broken out by PADD. Therefore, in Chapter 6 we utilize data on western Canadian heavy oil imports into the U.S., broken out by PADD, as a proxy measure of COSRC imports in 2006. Though we know the numbers are not exact, they provide a good first approximation to U.S. refiner access to COSRC.

[1] The two categories combined contain conventional sources of oil such as bitumen diluents as well as COSRC. Because of this, the two combined overstate actual 2006 oil sands production by about 300,000 b/d.

IMPORTS BY REGION

Where does oil imported into the U.S. from western Canada go to? Figure 5-1 shows western Canadian oil import data by PADD and indicates that the bulk of the oil goes to PADD II, which stretches from the upper Midwest down to Oklahoma. Another large amount goes to PADD IV, the plains states and Rocky Mountain region. According to data in the figure, western Canada shipped 1.64 million b/d of crude oil to the U.S. in 2007.

Figure 5-1. Market Demand for Canadian Crude Oil by PADD—Actual 2007 and 2015 Potential (thousand barrels per day)



Source: Canadian Association of Petroleum Pipelines.

A variety of companies purchased this oil. In a few cases, they were not refiners, and U.S. oil import data do not always reveal who ultimately processed the crude. Thus, identifying where the crude went and the entity that ultimately processed it and marketed the resulting products would require more information. Further, even where refining companies imported the crude, they may have mixed it with other crudes or exchanged it with other refiners. This subject is taken up next.

MIXING OF OIL SOURCES

Mixing during Operations

In the ordinary course of the oil business, crude oils and products have many opportunities to mix with one another. Such mixing occurs at refineries, bulk terminals, and in pipelines. Crude and product swaps among companies render the origins of the oil even more difficult to untangle.

Crude oils are routinely mixed in crude pipelines so that, unless a special effort is made to isolate a particular crude, it likely would be mixed with others during its movement to refineries. A refinery might own a set of crudes as they travel together in a pipeline or it might take possession at the refinery gate. In the latter case, the crude mix would be purchased on an averaged basis, where the average pertains to the gravity, sulfur content, and other qualities of the mix.

Even when a unique crude is shipped to a refinery via pipeline, the refiner is likely to mix it with others in its crude oil holding tanks. It may have several sources of crude, and not all crudes arrive at the same time, so different crudes routinely are mixed with one another. Generally speaking, refiners limit the number of holding tanks to those necessary to keep the refinery operating efficiently. Thus, isolating particular crudes could require extra tanks devoted to that purpose and scheduling refinery runs just to accommodate the isolated crude oil.

After refining, much petroleum product is shipped via pipeline to product terminals. Routinely, products are shipped by type on a schedule set by the pipeline, for example, gasoline on day 1, diesel on day 2, etc. Refiners nominate the amounts they plan to ship, and like products from multiple refiners are shipped together at a scheduled time.

Product terminals also routinely mix fuels of a given type together. As with crude, older product is mixed with newer and more than one refining source may be accommodated at a single terminal plant. Because of the mixing that takes place along the petroleum product supply chain, by the time product leaves a terminal, a host of different crudes may have been used as inputs.

Because refiners, pipelines, and bulk terminal operators seek to optimize schedules and simplify their logistics, mixing of crude and of product is routine practice within the industry. Conceptually, isolation of particular crudes and products is doable, but it likely involves higher cost because of extra tankage and other resources that may be required and because the revised schedule of transport and refinery runs presumably will be less efficient than before.

Exchanges and Other Agreements

Oil companies routinely engage in exchanges of crude oil and product with one another, mainly to save on transport costs or to meet sudden unexpected surges or reductions in demand. A refiner needing product at location A might find it has little to sell at that point but has a surplus at location B, whereas another refiner might have product at A but needs additional product elsewhere. The two might arrange an exchange, possibly to take place at a given point in time but sometimes arranged such that delivery of the one takes place after the other.

In addition to exchanges, oil companies buy product from one another for purposes of meeting demand when they have no readily available supply of their own to meet that demand. Such purchases provide refiners additional means with which to maintain a steady supply to their customers.

Statements concerning exchanges and purchases can be found in refiner financial reports. A typical statement is as follows:

> We also enter into refined product exchange and purchase agreements. These agreements help us minimize transportation costs, optimize refinery utilization, balance refined product availability, broaden geographic distribution, and make sales to markets not connected to our refined product pipeline system. Exchange agreements provide for the delivery of refined products by us to unaffiliated companies at our and third parties' terminals in exchange for delivery of a similar amount of refined products to us by these unaffiliated companies at specified locations. Purchase agreements involve our purchase of refined products from third parties with delivery occurring at specified locations.[2]

In some cases, companies market not only their own crude oil or product, but also those of others. These arrangements economize on marketing overhead, utilizing what already exists within larger companies to sell relatively small quantities on behalf of smaller entities. Thus, although a particular bulk lot may be sold by a single company, its constituent parts may include contributions from others.

Generally, companies specify the qualities of the crudes or products involved in purchases, exchanges, or marketing agreements, not their original sources. In many cases, those engaged in these transactions might not even have that information at hand. Thus, even if efforts were made to restrict purchases of product to refiners not obtaining it from oil sands crude, the use of purchases, exchanges, and joint marketing agreements by such a refiner could result in delivery of product that did contain it. Because these exchanges and agreements are widespread throughout the industry, fairly elaborate procedures would be necessary to prevent them from exposing an ultimate customer to oil sands-derived product.

[2] Valero Refining Company, 2007 10-K Report, p. 9.

Chapter 6
Estimated COSRC in DESC Bulk Fuel Purchases

We obtained data from DESC on its bulk fuel contracts in 2002–06 and adjusted them in two ways. First, because this study focuses on purchases in the United States, overseas shipping locations were removed.[1] Second, adjustments were made to the data to put all of it on the same fiscal year basis.[2] The resulting data set covers domestic purchases by DESC for FY03–06. Table 6-1 shows annual barrels awarded, by PADD.

Table 6-1. DESC Annual Bulk Fuel Awards, by PADD (millions of barrels)

PADD	FY03	FY04	FY05	FY06	Total by PADD
PADD I	3.0	0.0	12.0	20.0	35.0
PADD II	154.6	230.5	212.9	211.0	809.0
PADD III	1,118.6	1,643.2	1,784.6	1,749.7	6,296.1
PADD IV	79.8	116.7	104.5	100.1	401.2
PADD V	945.4	997.7	869.8	900.0	3,712.9
Total by year	2,301.4	2,988.1	2,983.8	2,980.8	—

From the table, most of the purchases over these years were made in PADD III (the Gulf Coast and Southwest, see Figure 5-1) and PADD V (West Coast). Relatively few were made in PADD I (East Coast), and intermediate amounts were purchased in PADD II (upper Midwest) and PADD IV (plains states and Rocky Mountains). The total amount purchased jumped in FY04 but then stayed relatively constant. Below, we analyze the processing of Canadian oil sands oil by DESC suppliers in each PADD.

[1] Shipments from locations in Bulwater Island, Australia; Montreal and Winnipeg, Canada; Yabucoa, Puerto Rico; and San Nicholas, Aruba, were removed from the data set.

[2] DESC's Bulk Fuels Summary of Awards is divided into a Rocky Mountain/West Coast Purchasing Program, which operates on a fiscal year calendar, and the Inland East Gulf and Offshore Purchasing Program, which utilizes an April-to-March calendar. Given that the Inland East Gulf and Offshore Purchasing Program is exactly 6 months off the beginning of each fiscal year, the quantity awarded was divided in half and each part was considered as part of the fiscal year that it overlaps. For example, if 100 barrels of oil were awarded in total for April 2002 through April 2003, then 50 barrels would be counted for FY02 and the other 50 for FY03.

PROCESSING CAPABILITY, BY PADD

PADD I

The data in Table 6-1 indicate that few purchases of military fuels were made by DESC in PADD I in FY03–06. DESC bulk purchase data indicate shipping points, which sometimes are from refinery locations but in other instances are from elsewhere. In the latter case, we assume that the product came from a company's refinery within the same PADD.

In PADD I, only one refinery, United Refining of Warren, PA, supplied DESC with product (Table 6-2) though Western Refining supplied DESC from a terminal in Maine. United Refining supplied DESC in only one year, FY03. During FY03–06, United Refining utilized western Canadian crude oil. The company did not have CorC capacity but used the heavy portion of imported Canadian crude to produce large quantities of asphalt and the lighter portion to produce higher-end products. According to United, over one-quarter of the refinery's output consists of asphalt.[3] The company's refining strategy and crude oil source imply that were it to again supply DESC, it likely would use a high proportion of COSRC to do so.

Table 6-2. PADD I Suppliers to DESC, FY03–06

Refiner	DESC purchase location	CorC capacity at nearest refinery?
United Refining	Warren, PA	No[a]
Western Refining	Buckstown, ME	No

[a] However, the company has been importing western Canadian heavy oil and processing it.

PADD II

Table 6-3 lists the refineries involved in supplying DESC with product in FY03–06 in PADD II. Four of them had the downstream processing capability to process substantial quantities of oil sands crude. All four are connected to the national crude oil pipeline system and could be supplied oil sands crude through it. In addition, Valero's refinery at Ardmore, OK, and Husky's refinery at Toledo, OH, are capable of processing COSRC though they were not suppliers to DESC in FY03–06. In the future, Sinclair's refinery at Tulsa, OK, also will be able to refine COSRC, as the company has announced a refinery expansion project aimed at processing such crude.

[3] "Asphalt production as a percentage of all refinery production has exceeded 26 percent over the last 5 fiscal years due to our ability and decision to process a larger amount of less costly heavy higher sulfur content crude oil." Source: United Refining 10-K Report for the Fiscal Year ending August 31, 2007, p. 5.

Table 6-3. PADD II Suppliers to DESC, FY03–06

Refiner	DESC purchase location	CorC capacity at nearest refinery?
Husky Oil	Lima, OH	Yes
Tesoro	Mandan, ND Moorehead, MN	No
ConocoPhillips	Oklahoma City, OK Ponca City, OK Wichita, KS	Yes
BP	Whiting, IN	Yes
Gary Williams	Wynnewood, OK	Yes

PADD III

In Table 6-4, we list refineries located in PADD III that supplied DESC product in FY03–06.

Table 6-4. PADD III Suppliers to DESC, FY03–06

Refiner	DESC purchase location	CorC capacity at nearest refinery?
Alon	Abilene, TX; Wichita Falls, TX	No
Delek Refining	Aledo, TX; Abilene, TX; Tyler, TX	Yes
ExxonMobil	Baton Rouge, LA; Pasadena, TX; Zachary Terminal, LA	Yes
Valero	Corpus Christi, TX; Sunray, TX; Texas City, TX; Three Rivers, TX	Yes
Deer Park (Shell/PEMEX)	Deer Park, TX	Yes
Western Ref.	El Paso, TX	No
Holly Corp.	El Paso, TX; Roswell, NM; Moriarty, NM	No
Calcasieu Ref.	Lake Charles, LA	No
Citgo	Lake Charles, LA	Yes
Shell	Mobile, AL	No
Pasadena Refining	Pasadena, TX	Yes
Placid Ref	Port Allen, LA	No
Hunt Ref	Tuscaloosa, AL	Yes
BP	Texas City, TX	Yes
Hinman	St. Rose, LA	No
Calumet Shreveport	Shreveport, LA	No
Age	San Antonio, TX	No

Many refining companies among DESC's PADD III suppliers—including large suppliers such as BP, Citgo, ExxonMobil, Deer Park Refining, and Valero—are capable of processing heavy crudes derived from oil sands. A few other refineries such as Hunt and Delek have some capacity to do so. All are connected to the national pipeline network and hence could receive COSRC. However, to date only relatively small amounts of Canadian heavy oil have been reaching PADD III refineries. In past years, such refineries are more likely to have processed Mexican and Venezuela heavy oils. Citgo is partially owned by PDVSA, the national Venezuelan oil company, while Deer Park Refining is a joint venture between Shell and PEMEX, the Mexican national oil company. However, Canadian oil sands production and pipeline expansion plans are aimed at expanding access to the PADD III market, so future increases in the amount of this oil processed there are likely.

PADD IV

In Table 6-5, we show PADD IV suppliers to DESC in FY03–06. Of these, only two, the Sinclair refinery at Sinclair, WY, and the ChevTex refinery in Salt Lake City, UT, have CorC capacity. Both refineries are connected to the Kinder Morgan Express pipeline that runs south from Hardisty. Also, other refiners in PADD IV that were not DESC suppliers in FY03–06 are capable of processing such crude. These include the ExxonMobil and Conoco refineries at Billings, MT, and the Frontier Refining Co. refinery at Cheyenne, WY.

Table 6-5. PADD IV Suppliers to DESC, FY03–06

Refiner	DESC purchase location	CorC capacity at nearest refinery?
ChevronTexaco	Salt Lake City, UT	Yes
ConocoPhillips	Commerce City, CO	No
Holly Corp R &M	Woods Cross, UT	No
Montana Ref Co.	Great Falls, MT	No
Sinclair	Sinclair, WY	Yes
Tesoro	Salt Lake City, UT	No
Wyoming Ref Co.	Newcastle, WY	No

PADD V

Table 6-6 lists PADD V suppliers to DESC in FY03–06. The West Coast is mostly isolated from Canadian oil in that there are no Canadian crude oil pipelines running south of Puget Sound. In addition, PADD V includes Hawaii and Alaska, which do not receive western Canadian crude oil. Table 6-6 indicates which PADD V supplier companies have refineries that could accommodate such oil.

Table 6-6. PADD V Suppliers to DESC, FY03–06

Refiner	DESC purchase location	CorC capacity at nearest refinery?
BP	Ferndale, WA	Yes
ChevronTexaco	Watson Station, CA	No
Corrigan	North Pole, AK	No
Eagle Aviation	Tacoma, WA	No
ExxonMobil	Torrance, CA	Yes
Flint Hills Ref	North Pole, AK	No
Paramount	Paramount, CA	No
Petrostar	North Pole, AK; Valdez, AK	No
Shell	Martinez, CA	Yes
Tesoro	Aiea, HI	No
U.S. Oil Refining	Tacoma, WA	No
Valero	Benicia, CA	Yes
Williams	Anchorage, AK; North Pole, AK	No

Of the four suppliers with oil sands processing capability, three are in California and one is in Ferndale, WA. Very little if any COSRC is presently being shipped to California.[4] Therefore, only the Washington location could have processed significant amounts of oil sands crude. That refinery is located very near the Trans Mountain pipeline from Edmonton running past Ferndale to Anacortes, WA. BP indicates that this refinery processes some Canadian oil but that most of its crude oil comes from Alaska.[5]

COSRC PROCESSING BY DESC SUPPLIERS

PADDs I and V

There were few direct pipeline links from western Canada to the eastern United States in FY03–06, though there was one from the Enbridge line at Sarnia, Ontario, to the United Refining refinery at Warren, PA. Enbridge has proposed alternative pipeline routes that could carry crude oil from the U.S. Midwest or from near Sarnia to Philadelphia, PA, and if one of these comes to fruition, PADD I suppliers beyond Warren potentially would have access to such oil. However, potential PADD I DESC suppliers other than United Refining also would have to construct the necessary processing capability, which would require substantial investment on their part.

[4] CAPP reports that small amounts of western Canadian crude are being shipped to California. They do not indicate whether COSRC is included.

[5] Private communication, BP to DESC, 2008.

In PADD V, among DESC suppliers capable of processing COSRC, only the BP refinery in Ferndale, WA, was near a pipeline transporting western Canadian crude in FY03–06. However, other refineries in the Puget Sound area, such as the Shell refinery at Anacortes, are capable of processing such oil.

Other future supply possibilities reside in PADD V. COSRC could be shipped by pipeline to Puget Sound and then transported in large quantities to California, where several DESC suppliers are capable of processing such oil. Further, U.S. Oil Refining in Tacoma, WA (a subsidiary of Transcor Astra, SA), indicated to LMI that it plans to upgrade its refinery to obtain 40 percent of its crude from Canada, half of which would be derived from oil sands. U.S. Oil Refining also indicates that it has begun processing small amounts of this oil. The U.S. Oil Refining facility can be supplied by the Trans Mountain pipeline from Edmonton. Thus, the number of PADD V suppliers capable of providing products made from COSRC is likely to increase over time.

PADDs II, III, and IV

Virtually all of the DESC suppliers located in PADDs II, III, and IV are connected to the national pipeline system and therefore could have utilized oil sands crude in FY03–06. However, limitations in pipeline capacity restricted the amounts of such crude flowing to certain parts of these PADDs. For example, only one pipeline, a reversed ExxonMobil pipeline from Patoka, IL, to Corsicana, TX, was capable of bringing Canadian crude oil to the Gulf Coast, and that line was limited to 65,000 b/d. The pipeline expansion projects described earlier in this report are meant to relieve these capacity constraints in the future.

From Tables 6-3, 6-4, and 6-5, four DESC suppliers in PADD II, five in PADD III, and one in PADD IV are presently capable of processing significant quantities of Canadian oil sands crude. In some cases, a single DESC supplier company is capable of such processing at several of its refineries. In the following subsections, we review information regarding each supplier by PADD, as well as plans by other suppliers to obtain the capability to supply product from oil sands crude.

PADD II Suppliers

In PADD II, the Husky Oil refinery in Lima, OH, has the requisite refinery capacity and is connected to the national pipeline system and hence could be receiving COSRC. However, Husky at Lima indicated to us that it does not process oil sands crude and has no immediate plans to do so, though over the longer term that is an option.[6]

BP at Whiting, IN, had downstream refining capability to process COSRC in FY03–06. The company has testified that it presently processes COSRC at this refinery and that it is investing between $3 and $4 billion to upgrade its

[6] Personal conversation with Jose Dominguez, Husky Oil Co., September 17, 2008.

capabilities so that it can process greater quantities of Canadian oil sands crude in the future. This capability is scheduled to come on line in 2010.

Firms that did not supply DESC in FY03–06 also are investing in COSRC processing capacity. ConocoPhillips and Encana, a Canadian firm, have entered into a partnership that includes oil sands properties and refineries, one of which is located at Wood River, IL, in PADD II. The Wood River refinery is being upgraded to handle large quantities of such oils in the future, around 2015.

Marathon Oil is investing $1.9 billion in its Detroit, MI, refinery to expand its processing capability and to enable it to handle oil sands crude. The project got underway in 2008 and is expected to be completed by 2010.

BP and Husky have formed a partnership that includes BP's refinery at Toledo, OH, as well as Canadian oil sands properties. The companies have announced a $2.5 billion plan to expand COSRC processing capability at the refinery from 60,000 to 170,000 b/d. The expansion is to be completed by 2015.

Sinclair Oil is investing about $1 billion in its Tulsa, OK, refinery to increase its capacity and to enable it to process oil sands oil. This project, too, is expected to be completed by 2010.

PADD III Suppliers

In PADD III, eight DESC suppliers are capable of processing oil sands crude, though only five have significant capacity to do so. One of these suppliers, ExxonMobil, is capable of supplying product processed from oil sands from its refineries at Baton Rouge, LA, and Baytown and Beaumont, TX, and from its terminal at Zachary, LA. Another supplier, Valero, could supply it from its Texas refineries at Sunray, Three Rivers, Corpus Christi, and Texas City. Both ExxonMobil and Valero have the capability to ship oil sands derived crude south from Cushing, OK, via the reversed ExxonMobil pipeline. The three other PADD III DESC suppliers capable of processing substantial quantities of oil sands crude include the Shell-PEMEX Deer Park, TX, refinery; the Citgo refinery at Lake Charles, LA; and the BP refinery at Texas City, TX.

Our discussions with Valero resulted in the following conclusions. First, the company has been processing oil sands crude in its Gulf Coast refineries. Second, it is routinely mixed with other crudes so that it is impossible to know the proportion of oil sands crude used in any given product. And third, Valero plans to expand its use of Canadian oil sands crude over time as pipeline projects to bring that crude to the Gulf Coast are completed. Basically, Valero intends to replace declining supplies of heavy crude from other sources with Canadian heavy crude.

Citgo petroleum company is a wholly owned subsidiary of PDVSA, the Venezuelan national oil company. Though the Lake Charles, LA, Citgo plant is capable of processing COSRC, it probably processes mainly Venezuelan crude

oils, including Venezuelan heavy crude.[7] Thus, we consider it unlikely that this refinery processed COSRC in FY03–06, but it likely produced product derived from (Venezuelan) extra heavy crude.

Similarly, though the Shell-PEMEX refinery at Deer Park, TX, is capable of processing COSRC, its ownership structure strongly suggests that it is oriented toward the processing of Mexican crude oil, which consists mainly of heavy oils. Press reports indicate that PEMEX supplies this refinery 200,000 b/d of crude oil and that the 330,000 b/d refinery obtains other crudes from Texas and Louisiana.[8] Mexican production has been dropping, so in the future, the refinery may have a greater interest in other sources. However, in FY03–06, this DESC supplier probably did not process COSRC.

We were unable to get information directly from ExxonMobil regarding its use of COSRC. ExxonMobil operates several large refineries in PADD III, all of which are capable of processing Canadian oil sands crude. ExxonMobil's ownership of the ExxonMobil reversed Pegasus pipeline from Cushing, OK, suggests that COSRC probably was one source of crude supply to some of its PADD III refineries in FY03–06. However, a fact sheet issued by the Baton Rouge refinery in November 2006 described its sources of crude, and they did not include Canada.[9] Hence, at least through that date, DESC's product supply from the Baton Rouge refinery likely did not include Canadian oil sands crude.

BP's communication to DESC indicates that it has used Canadian heavy crude at its Texas City, TX, refinery though it did not indicate whether that crude included COSRC. The refinery is the third largest in the United States and hence requires large quantities of crude oil. We speculate that even if the refinery did not process COSRC in FY03–06, it is likely to do so in the future, as supplies of that crude to this region increase.

The joint venture between ConocoPhillips and Encana mentioned above involves a refinery at Borger, TX, that is being upgraded to process oil sands crude. This refinery capability is scheduled to come on stream in 2015.

PADD IV Suppliers

In PADD IV, only two DESC suppliers during the years FY03–06, Sinclair Refining of Sinclair, WY, and ChevTex of Salt Lake City, have a present capability to process significant amounts of Canadian oil sands oil. Sinclair lies south of the Kinder Morgan Express pipeline bringing oil from western Canada and is connected to that pipeline. However, we were unable to secure information from Sinclair concerning its use of COSRC at this refinery.

[7] At its website, Citgo states, "Citgo's relationship with PDVSA assures the Lake Charles Refinery a stable supply of crude oil."

[8] "PEMEX cuts crude supply to Shell, Valero refineries in Texas," Bloomberg News Service, July 7, 2008.

[9] ExxonMobil Refining & Supply, Baton Rouge Refinery Fact Sheet, November 13, 2006.

At least one other potential supply source within PADD IV, ExxonMobil's refinery at Billings, MT, is capable of processing oil sands oil, though it did not supply DESC in FY03–06. That refinery is not far from the Kinder Morgan Express pipeline from Hardisty, but it is not directly connected to that pipeline.

Summary

Table 6-7 summarizes the information described above.

Table 6-7. DESC Supplier COSRC Use in FY03–06 and Near Future

Entity	Location	Used COSRC FY03–06?	Likely to use in near future?
PADD I–DESC supplier			
United Refining	Warren, PA	Yes	Yes
Western Refining	Buckstown, ME	No	No
PADD II–DESC supplier			
Husky Oil	Lima, OH	No	Yes
Tesoro	Mandan, ND	No	No
Tesoro	Moorehead, MN	No	No
Conoco-Phillips	Oklahoma City, OK	Uncertain	Uncertain
Conoco-Phillips	Ponca City, OK	Yes	Yes
Conoco-Phillips	Wichita, KS	No	No
BP	Whiting, IN	Yes	Yes
Gary Williams	Wynnewood, OK	Uncertain	Probable
PADD III–DESC supplier			
Alon	Abilene, TX	No	No
Alon	Wichita Fall, TX	No	No
Delek	Aledo, TX	No	No
Delek	Abilene, TX	No	No
Delek	Tyler, TX	Uncertain	Uncertain
ExxonMobil	Baton Rouge, LA	Probable	Yes
ExxonMobil	Zachary Terminal,	Probable	Yes
ExxonMobil	Pasadena, TX	Probable	Yes
Valero	Three Rivers, TX	Yes	Yes
Valero	Corpus Christi, TX	Yes	Yes
Valero	Sunray, TX	Yes	Yes
Valero	Texas City, TX	Yes	Yes
Deer Park (Shell)	Deer Park, TX	Uncertain	Uncertain
Western Refining	El Paso, TX	No	No
Holly Corp	El Paso, TX	No	No
Holly Corp	Roswell, NM	No	No
Holly Corp	Moriarty, NM	No	No
Calcasieu Refining	Lake Charles, LA	No	No
Citgo	Lake Charles, LA	Uncertain	Uncertain
Shell	Mobile, AL	No	No
Pasadena Refining	Pasadena, TX	Uncertain	Uncertain
Placid Refining	Port Allen, LA Tusca-	No	No
Hunt Refining	loosa, Al	Uncertain	Uncertain
BP	Texas City, TX	Uncertain	Probable
Hinman	St Rose, LA	No	No
Calumet Shreveport	Shreveport, LA	No	No
Age	San Antonio, TX	No	No

Table 6-7. DESC Supplier COSRC Use in FY03–06 and Near Future

Entity	Location	Used COSRC FY03–06?	Likely to use in near future?
PADD IV–DESC Supplier			
ChevronTexaco	Salt Lake City, UT	Uncertain	Probable
ConocoPhillips	Commerce City, CO	No	No
Holly Corp R&M	Woods Cross, UT	No	No
Montana Refining	Great Falls, MT	No	No
Sinclair	Sinclair, WY	Uncertain	Probable
Tesoro	Salt Lake City, UT	No	No
Wyoming Refining	New Castle, WY	No	No
PADD V–DESC Supplier			
BP	Ferndale, WA	Uncertain	Probable
ChevronTexaco	Watson Station, CA	No	No
Corrigan	North Pole, AK	No	No
Eagle Aviation	Tacoma, WA	No	No
ExxonMobil	Torrance, CA	No	Uncertain
Flint Hills Refining	North Pole, AK	No	No
Paramount	Paramount, CA	No	No
Petrostar	North Pole, AK	No	No
Petrostar	Valdez, AK	No	No
Shell	Martinez, CA	Uncertain	Uncertain
Tesoro	Aiea, HI	No	No
U.S. Oil Refining	Tacoma, WA	No	Yes
Valero	Benecia, CA	Uncertain	Uncertain
Williams	Anchorage, AK	No	No
Williams	North Pole, AK	No	No

The table indicates the following for 2006:

- *PADD I—2 suppliers*. One of the two used COSRC in FY03–06 and likely will continue to do so.
- *PADD II—5 suppliers*. Two used COSRC in FY03–06; two others are uncertain. For the future, three indicate they will be using it, one other probably will, and another is uncertain.
- *PADD III—17 suppliers*. One used COSRC in FY03–06, another probably did, and six others are uncertain. For the future, we estimate two will use COSRC, another is probable, and five are uncertain.
- *PADD IV—7 suppliers*. Two are uncertain users, but both appear probable in the future because of their proximity to COSRC.
- *PADD V—13 suppliers*. Three are uncertain users of COSRC. In the future, one will use COSRC, two are probable, and three more are uncertain.

Across the PADDs, there were 44 suppliers, some of them the same company in different PADDs. Only four state outright that they have been processing

COSRC. We rate 1 other as probable and 15 more as uncertain. This suggests that as few as 4 and as many as 19 could already have been processing COSRC.

In the near future, at least six suppliers will be using COSRC, six others are probable, and nine more are uncertain. In all, as many as 21 of DESC's suppliers could be processing COSRC oil within a few years.

ESTIMATING COSRC IN DESC FUEL PURCHASES

So far, we have sought to identify DESC suppliers that either are using COSRC already or plan to use it in the near future and those that might be using it or might use it soon. We now look at the problem from a different perspective, namely, how much COSRC U.S. refiners might be using on the basis of what we know about COSRC shipments to the United States by PADD and refinery capacity to process it.

We use six successive refinements of these data to estimate the fraction (D_c) of COSRC in the DESC supply:

1. Total Canadian crude supply as a fraction of total U.S. refinery capacity.

2. Total COSRC supply as a fraction of total U.S. refinery capacity.

3. Total imports of COSRC as a fraction of total U.S. refinery capacity.

4. Total imports of COSRC as a fraction of total refinery capacity for each PADD.

5. Total imports of COSRC as a fraction of refinery capacity, based on downstream processing capacity, by PADD.

6. Refiner by refiner imports of COSRC, based on downstream refining capacity in 2006, by PADD.

In the following subsections, we discuss each of these methods, presenting the results, reporting our assumptions, and describing the advantages and disadvantages.

As mentioned in Chapter 5, there are no precise data on how much COSRC is imported into the United States. However, as explained in that chapter, heavy oil exports from Canada provide a reasonable proxy measure, and CAPP provides information on how much western Canadian heavy oil was exported to the U.S. in 2006 by PADD. Because we are forced to use a proxy measure we recognize that the numbers are inexact, but they provide a good first estimate for our purposes.

Method 1

We calculate total Canadian crude supply as a fraction of total U.S. refinery capacity.

Let

t = the total annual production of crude in Canada,
T = total U.S. refinery capacity, and
C = an estimator of D_c,

then the estimate of COSRC in the DESC supply D_c is

$$D_c \sim C = t/T. \tag{1}$$

Taking t as 2.1 million b/d and T as 17.4 million b/d, we compute C = 12.1%.

This estimate assumes the following:

- All Canadian crude is derived from oil sands.
- All Canadian crude goes to U.S. markets.
- The ratio C is the same for all refineries in the United States.

None of these assumptions is very good. Only about half of Canadian crude production is from oil sands. Some Canadian crude goes to other countries, and some is refined within Canada. We are confident that the ratio C is not the same for all refineries in the United States

So Method 1 is faulty in all three assumptions, and both terms used to calculate C contain significant errors.

Method 2

We calculate total COSRC supply as a fraction of total U.S. refinery capacity.

We can refine our estimate of the fraction of COSRC in the DESC supply by recognizing that not all of the crude production in Canada derives from oil sands.

Let

t' = the total annual production of COSRC,
T = total U.S. refinery capacity, and
C' = a second estimator of D_c, then

$$D_c \sim C' = t'/T. \tag{2}$$

Taking t' as 1.1 million b/d and T as 17.4 million b/d, we compute $C' = 6.3\%$.

Method 2 assumes the following:

- All COSRC goes to U.S. markets.
- The ratio C' is the same for all refineries in the United States.

For the reasons discussed above, neither of these assumptions is very good. So Method 2 is faulty in both assumptions, and both terms in equation (2) contain significant errors. It also is not a useful upper or lower bound on D_c although C' is an improvement on C from equation (1).

Thus, DESC needs a better estimate of D_c.

Method 3

We calculate imports of COSRC as a fraction of total U.S. refinery capacity.

We can further refine our estimate of the fraction of COSRC in the DESC supply by recognizing that not all COSRC is exported to the United States. A small amount of western Canadian production is exported to other countries from a terminal in Puget Sound reached via the Trans Mountain Pipeline (see Figure 4-4). Other production is refined in Canada and goes into the Canadian fuel supply. There are two refineries in Quebec, four in Ontario, and seven in western Canada.

Let

t'' = the total COSRC exported to the United States,
T = total U.S. production of refined product, and
C'' = a third estimator of D_c, then

$$D_c \sim C'' = t''/T. \tag{3}$$

Equation (3) provides a more useful estimate of D_c. Using values for 2006, we take t'' as 1.039 million b/d and T as before as 17.4 million b/d, which gives C'' = 6.0%.

This estimate assumes the ratio t'' is the same for all refineries in the United States.

Method 4

We calculate imports of COSRC as a fraction of total U.S. refinery capacity, by PADD.

We can improve our estimate of D_c if we recognize that COSRC does not reach all refineries in the United States. Pipelines capable of carrying this material do

not extend to all parts of the country, and water transport may not be feasible or competitive compared with other sources of crude. Examples include much of the eastern United States, which is not reached by such pipelines, and the southern part of the west, also not reached by pipeline.

Considering the relative contribution of COSRC by PADD will allow us to refine our estimate and identify different supply situations. For this purpose, we use CAPP estimates of the supply of heavy crude oil exported to each PADD.[10]

Let

t_p = the total COSRC imported to PADD p,
T_p = total refined product for PADD p, and
C_p = an estimator of COSRC as a proportion of refinery capacity by PADD,
then

$$D_{cp} \sim C_p = t_p/T_p. \tag{4}$$

Table 6-8 reports the results of these calculations. Equation (4) provides information concerning the PADDs that are producing refined product that contains high (or low) proportions of COSRC and, hence, those that probably contain COSRC-derived product reaching the DESC supply chain.

Table 6-8. COSRC Fraction of Processing by PADD

PADD	Estimated COSRC imports (b/d)	Refinery capacity (b/d)	COSRC fraction (%)
I. East Coast	<63,000	1,600,000	<4
II. Midwest	715,000	3,600,000	20
III. Gulf Coast	65,000	8,600,000	1
IV. Rocky Mt	158,000	400,000	40
V. West Coast	18,000	3,200,000	1
Total	<1,019,000	17,400,000	6

This estimate assumes the ratio t_p/T_p is the same for all refineries in a PADD.

Method 5

We calculate the imports of COSRC as a fraction of refinery capacity on the basis of downstream processing capacity, by PADD.

We can refine these PADD estimates of COSRC relative to refinery capacity a little further. The estimates of Table 6-8 assume that COSRC is distributed equally among refiners in each PADD, but we know that not all refiners have the

[10] Canadian Association of Petroleum Producers, *Crude Oil Forecast, Markets and Pipeline Expansions*, June 2007, p. 9-14.

downstream refining capacity to process large quantities of heavy crude and that not all supplied DESC in FY06. By focusing only on those refiners with either catalytic hydrocracking or coking (CorC) capacity and within that group only those that supplied DESC in that year, we can further refine our estimates. We illustrate our approach with PADD II data (Table 6-9) and then offer the results for all PADDs.

Table 6-9. COSRC Fraction of Crude Processed by DESC Suppliers in PADD II on Basis of CorC Capacity (b/d)

1. DESC Supplier CorC Capacity	105,378
2. Non-DESC Supplier CorC Capacity	425,202
3. Fraction of COSRC cracking/coking capacity owned by DESC refiners	20%
4. Daily COSRC imports to PADD	715,000
5. Daily COSRC to DESC Suppliers (line 3 × line 4)	143,000
6. Total DESC Supplier Refining Capacity	1,008,240
7. Output of PADD II DESC refineries that is from COSRC (line 5/line 6)	14%

DESC suppliers had about 20 percent of all CorC capacity in PADD II in 2006. Applying this ratio to the 715,000 b/d of COSRC estimated to have been supplied there (assuming implicitly that all COSRC was sent only to refineries with such capacity), about 143,000 b/d were processed by those refineries. This was about 14 percent of their overall refining capacity, a smaller number than the 20 percent shown in Table 6-8. For all five PADDs, Table 6-10 shows our estimates using this method.

Table 6-10. COSRC Fraction of Crude Processed by DESC Suppliers in 2006 on Basis of CorC Processing Capacity, by PADD

PADD	Percentage
1. East Coast	0[a]
2. Midwest	14
3. Gulf Coast	1[b]
4. Rocky Mountains	21
5. West Coast	1

[a] The only refinery in PADD I that received COSRC was not a DESC supplier in FY06.

[b] In PADD III, one DESC supplier was excluded because it was a terminal operator and had no refining capacity. The company supplied less than 0.6% of DESC purchases in the PADD for that year.

Method 6

Finally, we break down the figures in Table 6-10 refiner by refiner. The method is similar to that shown in Table 6-9, using CorC capacity to indicate ability to process COSRC, except that it is applied at the individual refiner level. Specifically, COSRC is assumed allocated among DESC suppliers according to their proportion of PADD CorC capacity and then shown as a percentage of their total refinery capacity. Table 6-11 summarizes the results for all five PADDs. The figures in the table should be read as the potential each refiner had to process COSRC in 2006 on the basis of estimated imports of this oil into the PADD and relative CorC capacity.

Table 6-11. Potential COSRC Fraction of Crude Processed in 2006, by Individual DESC Supplier

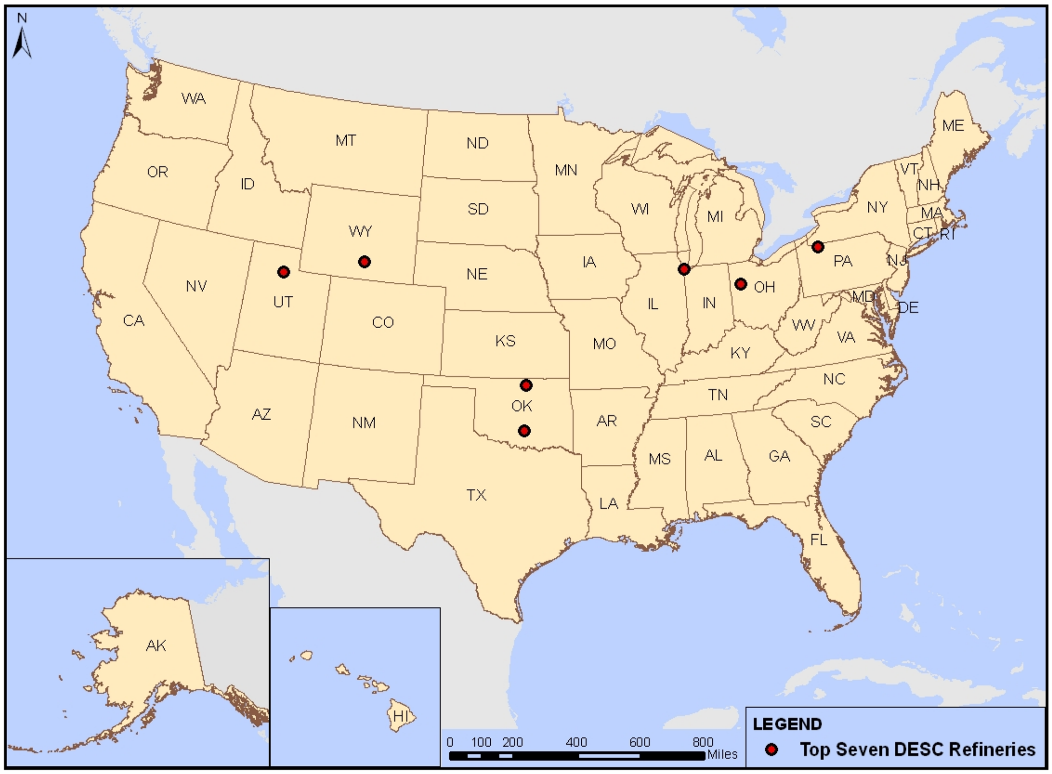
Contractor and shipping location	PADD	COSRC as percentage of refinery output
BP-Husky: Lima, OH	2	27
ChevTex; Salt Lake City, UT	4	16
Sinclair: Sinclair, WY	4	16
ConocoPhillips: Oklahoma City, OK	2	14
Gary Williams: Wynnewood, OK	2	11
BP; Whiting, IN	2	8
Shell; Deer Park, TX BP: Texas City, TX Hunt; Tuscaloosa, AL Valero; Corpus Christi, TX Valero; Three Rivers, TX	3 3 3 3 3	1–2
ExxonMobil: Baytown, TX ExxonMobil; Baton Rouge, LA Citgo, Lake Charles, LA Valero; Texas City, TX RAOT; Pasadena, TX ConocoPhillips; Ponca City, OK Valero; Sunray, TX DELEK; Tyler, TX BP West; Ferndale, WA Valero; Benecia, CA Shell; Martinez, CA Tesoro; Aiea, HI	3 3 3 3 3 3 3 3 5 5 5 5	<1

Table 6-11. Potential COSRC Fraction of Crude Processed in 2006, by Individual DESC Supplier

Contractor and shipping location	PADD	COSRC as percentage of refinery output
Western Ref; Bucksport, PA	1	0
Tesoro; Mandan, IN	2	
Calcasieu; Lake Charles, LA	3	
Placid Ref; Port Allen, LA	3	
Shell; Mobile, AL	3	
Calumet; Shreveport, LA	3	
Western Ref; El Paso, TX	3	
Age Ref; San Antonio, TX	3	
Alon; Abilene, TX	3	
Alon; Wichita Falls, TX	3	
Holly Corp; Artesia, TX	3	
Wyoming Ref; Newcastle, WY	4	
ConocoPhillips; Commerce City, OK	4	
Holly Corp; Woods Cross, UT	4	
Montana Ref; Great Falls, MT	4	
Petrostar: Valdez, AK	5	
Petrostar; North Pole, AK	5	
U.S. Oil; Tacoma, WA	5	
Paramount; Long Beach, CA	5	

Method 6 allows us to more precisely identify which refiners potentially had the highest proportions of COSRC in their crude input stream in 2006, by PADD. According to the table, given COSRC allocation among the PADDs in 2006, only six DESC suppliers potentially utilized it for more than 2 percent of their crude inputs. Not surprisingly, all are located in PADDs II and IV. The locations of the six plus United Refining of Warren, PA, which only supplied DESC in 2003 but which processes virtually 100 percent western Canadian oil are denoted by the red circles in Figure 6-1.

Figure 6-1. Location of DESC Suppliers That Potentially Used COSRC for More Than 2 Percent of Crude Inputs, 2006



Source: Monica DeAngelo, LMI GIS. Location of DESC Suppliers that Potentially used COSRC for more than 2 Percent of Crude Inputs, 2006 [map]. 1:33,000,000, USA Contiguous Albers Equal Area Conic, NAD83. *Internal database for DES86.02 (DESC_refineries.dbf) [computer file]*. McLean, VA: October 2008. Using ArcView GIS Version 9.3. Redlands, CA: Environmental Systems Research Institute, Inc, 2008.

A couple of qualifications regarding our approach are in order. Table 6-11 is based on the assumption that if a refinery did not have CorC capacity it did not process significant quantities of COSRC in 2006. But as stated earlier, we know from the example of United Refining in Warren, PA, that some refineries without such capacity could have processed this crude to make a high percentage of asphalt or other low-end products. We know, too, that some refiners that could have processed a high potential percentage of COSRC indicate that they are not yet processing it (such as BP-Husky at Lima, OH). So, the estimates in Table 6-11 are only approximations and may be off target in a few instances.

Nevertheless, a general picture emerges. DESC's 2006 suppliers in PADDs I, III, and V probably did not process high proportions of COSRC. Some of its suppliers in PADDs II and IV could have utilized this source for as much as a quarter of their crude input, but none relied on it for the preponderance of such input. In fact, the only company that did so (of which we are aware) was United Refining, which did not supply DESC in 2004–06. Thus, at the present time, few suppliers would be much affected by section 526 unless it applied to incidental amounts

and this term were defined as being less than 2 percent of crude supply or even less than that.

We know, however, that COSRC production and exports are expected to expand over time, possibly even tripling by 2020. What would the percentages look like with expanded exports of COSRC to the United States?

Much depends on where the incremental COSRC would be shipped. From our review in Chapter 4, several pipeline projects are aimed at expanding access into PADD III, the Gulf Coast, to take advantage of the broad market there. Our estimates indicate that no PADD III supplier presently uses COSRC for more than 2 percent of its crude input. It would take a very large buildup of supply into that area to much change that statistic. The same is true for much of PADD V, particularly the California market, which is very large. But if COSRC supply into PADDs II and IV is expanded over time, some refiners there likely would use more than the relatively high proportions they do now. Depending on which refiners in those PADDs purchase incremental COSRC supply, a few might eventually have trouble complying with section 526, even under a relatively benign interpretation of the provision.

Chapter 7
Implications for DESC

This report gives a fairly comprehensive picture of DESC's U.S. bulk fuel suppliers in FY03–06, those that had the capability to process significant quantities of Canadian oil sands crude, and those that either did so or are planning to do so in future. To date, for most U.S. refiners, Canadian oil sands crude is a fairly small part of the input stream, but it is a fairly large fraction for a few refiners, and projections of future COSRC output and announced pipeline expansion plans make it clear that it will be an even larger fraction in the future. Also, from our information concerning individual refiner plans, more suppliers at more locations will be processing COSRC.

We did not carefully examine the quantity and destinations of Venezuelan heavy crude oil shipped to the United States. However, media reports indicate that about 600,000 b/d of such crude is exported by Venezuela and that much of it goes to U.S. Gulf Coast refineries. This 600,000 b/d is in addition to oil sands crude shipped to the United States from Canada. However, even if all of this crude were shipped to PADD III refineries, it would make up only about 7 percent of refinery capacity there. Counting only PADD III refineries capable of processing such crude, though, the proportion would be higher.

The impact of section 526 on DESC will depend upon its meaning. If the standard applies only to contracts that stipulate that COSRC must be utilized in the production of products, it probably would have little effect. Similarly, if the provision means that products supplied DESC cannot be *predominantly produced from* oil sands crude, and this refers to a majority of crude input, it also probably would not have much effect, except in a few isolated cases. If however the standard is that products supplied DESC can be derived from only *incidental amounts* of oil sands crude, then depending on how this term is defined some suppliers might have to modify their operations in order to comply.

Only a relatively small proportion of DESC supplier companies were capable of processing significant quantities of COSRC in FY03–06. If DESC wished to avoid product from these sources, it could attempt to switch among suppliers so that those it continues to use do not process COSRC except in small quantities.

However, this poses at least two problems. DESC desires as much supplier competition as possible, and this approach would reduce the number of competitors. Also, some of the nation's largest, most sophisticated refineries are processing or will process COSRC, and a few of them have been supplying significant quantities of product to DESC for years. Whether other suppliers could fully compensate is unclear. Even if they did, however, the costs of fuel to DESC

are likely to rise because the previously supplying refiners presumably were the low bidders.

Another approach would be to contractually stipulate with refiners or other suppliers that no more than minimal amounts of COSRC could be utilized in products supplied to DESC. We have not asked refiners to describe how they might comply with such a contractual requirement, and they may be able to easily schedule their runs such that non-COSRC crude is processed when they are producing products for the U.S. government while COSRC crude input is reserved for others. However, there is a history of refiners being asked to supply "boutique" motor fuels, and some refiners may follow procedures sometimes used to deal with such circumstances. These involve building extra tanks to isolate the particular product at issue. In this case, refiners might build tanks to isolate crude known not to contain COSRC, schedule the processing of that crude separately from other processing, and then store the resulting product separately from other product before shipping. If that strategy were followed, the additional crude and product tanks would add to costs and suppliers presumably would charge DESC higher prices to cover the increase.

In some cases, isolating crude not derived from COSRC might have to begin upstream of a refinery gate. Crude oil pipelines, for instance, might have to stipulate to shippers that they not mix COSRC with other crudes. Isolation of COSRC from other crudes within the pipeline system might require yet further tanks to be built.

We did not examine DESC's domestic direct purchase programs such as into-airplane, nor did we look into its international purchases. Under a strict definition of section 526, these components of DESC's fuel purchase activities will require investigation and the use of unconventional crude oil to make product in these areas documented.

Finally, because COSRC evidently will become a larger share of U.S. refinery input than it is today, a DESC requirement for minimal COSRC refinery product content is likely to become increasingly difficult to manage. Fewer refiners may be willing to supply DESC, and costs of supply for those that remain are likely to increase. Also, with pipeline expansion projects coming on line, more areas will receive such crude, so suppliers who previously made little use of oil sands crude probably will begin to do so. In some cases, this could mean they would no longer be willing to supply DESC if that meant having to isolate non-COSRC crude and derived product at their facilities.

Chapter 8
Conclusions

For DESC to comply with section 526 of EISA, it must know what the law requires of it and its suppliers. The law is not completely clear concerning what is covered nor the amounts involved. For example, one interpretation is that section 526 is not meant to apply to oil products purchased in the ordinary course of business and that DoD is only constrained from *specifically contracting for* products produced from oil sands crude. Under this interpretation, routine purchases of product, some of which might be derived from oil sands crude, would not be affected.

A second interpretation is that products supplied DESC cannot be *predominantly produced from* oil sands crude. Assuming this refers to situations in which the majority of a supplier's product is produced from oil sands crude, this standard probably would not much inhibit DESC.

However, if the standard were that products supplied DESC can include only *incidental amounts* of oil sands crude, chances are that some suppliers would have to modify their operations. The number of suppliers affected and the extent of such modification would depend upon what is meant by "incidental," which is not defined in the legislation.

In FY03–06, DESC obtained petroleum bulk supply in all five U.S. PADDs. Limited amounts of COSRC were shipped to PADDs I, III, and V. A good deal of such oil was shipped to PADDs II and IV, where it constituted a fairly high proportion of crude oil inputs to refineries. For the future, chances are that more COSRC will be shipped to PADD III as producers seek higher prices by securing improved access to markets along the U.S. Gulf Coast. A number of pipeline projects are intended to facilitate such improved access.

Crude oil and oil products are routinely mixed together in pipelines and at refineries and terminals. Also, crude and products frequently are swapped among refiners. Because of this mixing and trading along the petroleum product supply chain, it can be difficult for a product supplier to know the exact sources of crude that were used.

Refiners invest in certain types of processing equipment to handle large quantities of heavy crudes such as those from oil sands. Generally, refiners who process significant quantities of such crudes have CorC. We examined which of DESC's suppliers possessed such equipment in FY03–06 and which are planning to add it over the next few years.

Taking into account CorC processing capability plus access to pipelines, published reports, and private communications, we could identify only four DESC suppliers that definitely have been processing COSRC. However, using the same sources of information, we identified 15 others as probable or uncertain with respect to COSRC use, so that as many as 19 may already have been processing it. In the near future, up to 21 DESC suppliers may use COSRC, and 6 of them are openly planning to do so.

We also sought to quantify how much COSRC each DESC supplier *potentially* could have processed. Using ownership of CorC equipment as a proxy for processing capacity for oil sands crude, we provide estimates of the amounts potentially used by DESC suppliers in 2006 as a proportion of their refining capacity. By these estimates, only six suppliers potentially processed more than 2 percent COSRC in that year. Five more potentially could have processed between 1 and 2 percent and another 12, less than 1 percent. These numbers do not exactly accord with the numbers reported above because some refiners with heavy oil processing capacity are understood not to have been processing Canadian oil sands crude at the time.

If DESC is forced to purchase bulk oil product containing only minimal quantities of COSRC, it may have to require some of its suppliers to isolate non-COSRC oil and product refined from it. This will likely result in fewer suppliers than otherwise, and costs of supply to DESC would rise. However, we did not investigate how refiners would comply with this type of requirement or what the costs to DESC would be.

Separately, we briefly examined F-T-derived fuels (see Appendix A), another fuel type that could be affected by section 526. To date, the process has only been used in a research context to produce fuels in the United States. Different inputs to F-T plants have different life-cycle GHG consequences: coal-derived fuels have higher GHG emissions than fuels derived from petroleum. Because of this, DESC would be constrained by section 526 from contracting specifically for fuel supply from a coal-to-liquids plant using F-T technology, except as part of a research project related to that fuel.

Appendix
Potential for F-T Fuels in DESC Supply

Under section 526, unconventional fuels produced via the F-T process may be problematic for DESC in some instances. The main issue is the energy source fed into the process.

The F-T process was developed in Germany in 1923 by Franz Fischer and Hans Tropsch. They converted syngas (a gaseous mixture comprising carbon monoxide, carbon dioxide, and hydrogen) into long chains of liquid hydrocarbons. The first F-T plant opened in Germany in 1938 and closed shortly after World War II. At one time, Germany's synthetic fuel production reached more than 124,000 b/d from 25 plants.[1]

F-T Processes

The F-T process works through a series of catalyzed reactions to convert synthetic gas into liquid hydrocarbons that can be used for fuel. In the F-T process, syngas is inserted into a reactor, where it is converted to paraffin and is then hydrocracked (a process conducted in the presence of hydrogen, which increases the yields of either gasoline or jet fuels) to produce hydrocarbon chains of various lengths. Coal, natural gas, or biomass feedstock can be converted into synfuels by two distinct F-T processes: liquid-to-liquid (LtL) or gas-to-liquid (GtL). Variants of the LtL process employ coal or biomass as the source material, whereas GtL involves the use of gaseous fuels such as natural gas or biogas.

Coal-to-liquids (CtL) processes have the potential to produce a range of useful fuels and chemicals, including transportation fuels such as gasoline, diesel, and methanol. The production of liquid transportation fuels from coal using the F-T process has been demonstrated on a large scale. The plants tend to be built at locations close to coal supplies and water sources, and where the liquid products and surplus electricity can be distributed to nearby demand regions.[2] CtL plants, however, also tend to produce higher life-cycle GHGs than fuels produced from petroleum.

Currently, the major biomass-to-liquids (BtL) production processes are GtL processes, involving conversion of biomass into a synthesis gas and then into liquids. Pyrolysis also is used, involving decomposition of biomass in the absence of

[1] U.S. Department of Energy, *The Early Days of Coal Research*, www.fe.doe.gov/aboutus/history/syntheticfuels_history.html.

[2] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2008: With Projections to 2030*, Office of Integrated Analysis and Forecasting, June 2008, www.eia.doe.gov/oiaf/aeo/pdf/0383(2008).pdf.

oxygen to produce a liquid fuel. One major benefit of BtL fuels is their compatibility with existing vehicle technologies and fuel distribution systems. Biomass-derived gasoline and diesel can be transported through existing pipelines, dispensed at existing fueling stations, and used to fuel today's gasoline- and diesel-powered vehicles.

WORLDWIDE F-T FACILITIES

Germany's use of the F-T process to convert coal to liquid fuels ended after World War II, but in 1955 Sasol of South Africa opened a CtL plant using the F-T process in Sasolburg and expanded the effort in 1980 and 1982 with two more plants at Secunda. The complex at Secunda is capable of producing 150,000 b/d.

In the 1990s, two more F-T plants came on line. Mossgas (currently PetroSA), which uses a high temperature F-T process and iron catalyst, opened in 1992. StatoilHydo and PetroSA operate a semi-commercial GtL demonstration plant there, which produces about 30,000 b/d of high quality fuels. The source is natural gas produced from natural gas fields offshore in Mossel Bay.[3] This is the largest GtL plant in the world.

Shell's Bintuli plant in Malaysia, which uses a slightly modified version of F-T called the Shell middle distillate synthesis process, was commissioned in 1993. A medium-sized plant there produced close to 12,500 b/d in its first year, and production since has risen to about 14,700 b/d.

Sasol is involved in a partnership with Qatar Petroleum to operate Oryx, a 34,000 b/d GtL plant in Qatar. Moreover, the two companies have signed a memorandum of understanding that by 2009 they will begin expanding the plant's output to 100,000 b/d.[4]

Table A-1 summarizes the above information.

Table A-1. Existing F-T Facilities

Stakeholders	Location	Process	Capacity (b/d)	Additional notes
PetroSA and StatoilHydro[a]	Mossel Bay, South Africa	GtL	36,000 45,000 (crude oil equivalent)	Completed mid-1990s, semi-commercial
Shell[b]	Bintulu, Malaysia	GtL	12,500 (1993) 14,700 (2005)	Operational since 1993

[3] upstreamonline.com, *PetroSA looks at Mossel Bay options*, March 22, 2006, www.upstreamonline.com/live/article107399.ece.

[4] Qatar Petroleum, *Gas-to-Liquids (GTL) Projects*, 2006, www.qp.com.qa/qp.nsf/web/bc_new_projects_GtL.

Table A-1. Existing F-T Facilities

Stakeholders	Location	Process	Capacity (b/d)	Additional notes
Sasol and Qatar Petroleum	Oryx, Qatar	GtL	9,000 (average 2008)[c] 16,000 (2008)[d] 34,000 (future)[e]	Opened the latter half of 2008 Largest GtL plant outside of South Africa Production will continue to increase
Sasol, sasol synfuels	Secunda, South Africa	CtL	150,000[f] 180,000 (by 2015)	World's only operating CtL plant

[a] www.petrosa.co.za/.
[b] www.shell.com/home/content/qatar/bintulu/bintulu_malaysia_08102003_1230.html.
[c] www.fin24.com/articles/default/display_article.aspx?ArticleId=1518-24_2350507.
[d] www.fin24.com/articles/default/display_article.aspx?Nav=ns&ArticleID=1518-24_2285359.
[e] www.qp.com.qa/qp.nsf/web/bc_new_projects_GtL#.
[f] www.southafrica.info/business/investing/sasol-221007.htm.

GAS-TO-LIQUIDS

GtL Emissions

A report produced by Shell, ConocoPhillips, and SasolChevron concluded that GtL emits fewer GHGs than the production and use of conventional diesel fuel.[5] According to another recent Shell study, the product from GtL also lowers local emissions such as nitrous oxide (by 6 percent), particulates (26 percent), hydrocarbon (63 percent), and carbon monoxide (91 percent). An independent study carried out by the California Energy Commission determined that GtL is the most cost-effective alternative fuel for reducing emissions.[6] GtL also is estimated to produce 40 percent less solid waste than the production of conventional diesel and to contribute less air acidification and hence less formation of smog.[7]

Shell has teamed up with a number of major cities around the world to see whether GtL could have a positive impact on urban air quality as well as carbon dioxide (CO_2) emissions. The most recent test data, announced in Shanghai last September, indicate that Shell GtL fuel used in buses can reduce CO_2 by 4 percent, particulate matter by 35 percent, and smoke emissions by 70 percent compared with conventional diesel.

[5] www.shell.com/static/shellgasandpower-en/downloads/products_and_services/what_is_GtL/benefits_of_GtL/GtL_lca_synthesis_report.pdf.

[6] www.energy.ca.gov/2007_energypolicy/index.html.

[7] www.shell.com/home/content/shellgasandpower-en/products_and_services/what_is_GtL/benefits_of_GtL/GtLbenefit_0112_1630.html.

Planned GtL Facilities

In April 2005, Chevron and Sasol announced a $1.7 billion deal to construct the Escravos GtL project 100 km southeast of Lagos, Nigeria, which was planned for completion in 2009.[8] By September 2008, Sasol reduced its stake in Escravos to just 10 percent as projected construction cost rose to $6 billion and completion was delayed to 2011.[9] The original 34,000 b/d output capacity remains unchanged.

Shell and Qatar Petroleum are involved in a production-sharing project, Pearl GtL, which will have a 140,000 b/d capacity from two GtL trains, each capable of producing 70,000 b/d.[10] Construction on this site is divided into two phases: the first train is expected to be completed by the end of the decade, and the rest of the project is scheduled to be completed a year later. Shell is funding this project.[11]

ExxonMobil and the Nigerian National Petroleum Corporation announced in June 2008 that they had signed a $220 million financing deal with a group of Nigerian banks to build a natural-gas-to-liquid petroleum plant.[12] This joint venture will utilize Nigeria's estimated 180 trillion cubic feet of natural gas resources.[13] The project is still in the planning phase and has no set timeline for completion.

Ivanhoe entered into an agreement with Syntroleum Corporation to use its licensed GtL technology.[14] Since then, Ivanhoe has explored many options worldwide through a series of feasibility studies. At this point, it is only actively pursuing a GtL project in Egypt with the Egyptian Natural Gas Holding Company and H.K. Renewable Energy, Ltd. This partnership has plans to build a 47,000 b/d capacity commercial plant.[15]

In November 2005, the Industrial Development and Renovation Organization of Iran and Sarv Oil and Gas Company signed a contract on GtL plant construction. According to the contract, a GtL unit with a capacity of 1,000 b/d will be set up in an area between Saveh and Salafchegan within 3 years.[16]

Table A-2 shows planned GtL facilities.

[8] www.hydrocarbons-technology.com/projects/escravos/.

[9] www.greencarcongress.com/2008/09/sasol-reduces-e.html.

[10] www.dieselnet.com/news/2006/07shell.php.

[11] www.shell.com/home/content/aboutshell/our_strategy/major_projects_2/pearl_gtl/pearl_gtl_13032008.html.

[12] uk.reuters.com/article/rbssEnergyNews/idUKL2325243120080623?pageNumber=1&virtualBrandChannel=10174.

[13] www.africanoiljournal.com/09-03-2008_exxonmobil.htm.

[14] www.ivanhoe-energy.com/s/GTLTechnology.asp.

[15] www.ivanhoe-energy.com/i/pdf/2007-10K.pdf.

[16] www.taylor-dejongh.com/news/downloadFiles/articles/MEES-v49n17.pdf.

Table A-2. Planned GtL Facilities

Proposed FT facilities	Location	Investment	Capacity (b/d)	Status
Sasol, Chevron, and Escravos[a]	Nigeria	$6 billion	34,000	To be completed by 2011
Sasol, Shell, and Qatar Petroleum, production sharing agreement, Pearl GtL[b]	Qatar	$18 billion, with payback in 4 years	70,000 (increasing to 170,000)	Under construction, to be completed in phases in 2010 and 2011
Exxon, NNPC	Nigeria	$220 million	N/A	Announced June 2008
Syntroleum Corporation and Ivanhoe Energy, Inc.	Egypt	N/A	47,000	Joint project development plan for technology and projects
IDRO and Sarv	Iran	$340 million	1,000	Will be a semi-industrial plant

[a] www.engineeringnews.co.za/article.php?a_id=134976.
[b] www.shell-me.com/en/jul2007/feature3.php.

BIOMASS-TO-LIQUIDS

BtL Emissions

Technologies to produce BtL fuel are, for the most part, still in the research and development stages. The most commercially advanced BtL process is probably that of Choren, which is collaborating with Shell, Daimler-Chrysler, and Volkswagen on a BtL fuel it calls SunDiesel, a diesel-like fuel.[17] Choren plans to open an industrial-scale 15,000 ton/year pilot plant in Freiberg, Germany. It claims that GHG reductions of up to 91 percent are possible through the use of BtL.[18]

A DOE study compared SunDiesel performance with that of conventional diesel. The tests were performed on a 1999 Mercedes sedan and a Caterpillar heavy-duty, single-cylinder research engine. The preliminary results show that SunDiesel reduced tailpipe emissions by 10 percent and had cobenefits such as reduced sulfur and nitrogen oxides.[19]

Planned BtL Facilities

Syntroleum and Tysons, through a joint venture named Dynamic Fuels, LLC, are building a biorefining plant in Geismar, LA, which will utilize BtL production, processing biomass-derived F-T waxes, fats, oils, and grease. Syntroleum has

[17] www.choren.com/en/energy_for_all/sundiesel/.
[18] www.choren.com/en/choren_industries/information_press/press_releases/?nid=185.
[19] www1.eere.energy.gov/cleancities/toolbox/pdfs/renewable_diesel_white_paper_final.pdf.

further plans to integrate biorefining and BtL plants, which will each produce around 90 million gallons of fuel annually.[20]

Flambeau River Biofuels obtained a $30 million grant from DOE to construct and operate a gasification-based BtL diesel plant at an existing pulp and paper mill in Park Falls, WI.[21]

Verenium Corporation's Jennings BtL demo plant, a DOE-sponsored project, will be the first operational BtL plant and is scheduled to open in late 2008.[22] Verenium is looking to commercialize the project using a wide assortment of biomass feedstocks, including sugarcane bagasse, agricultural byproducts, waste wood products, and other nonfood-based energy crops.[23]

Neste Oil and a Finnish paper products company, Stora Enso, have recently announced a joint venture to build a pilot BtL facility to convert forest product residue into renewable fuel.[24] They are building a demonstration plant in Stora Ensco's mill in Finland, which is expected to start up in 2008.[25] The heat and electricity produced at the plant will be used locally.

Catchlight Energy, LLC, was formed by Chevron and Weyerhaeuser Co., one of the world's largest forest products companies. Catchlight's intention is to develop a next generation of renewable transportation fuels from nonfood sources. Its initial focus is developing and demonstrating novel technologies for converting cellulose and lignin from plant material into economical, low-carbon biofuels.[26]

Table A-3 shows planned BtL facilities.

Table A-3. Planned BtL Facilities

Stakeholders	Location	Investment ($ Million)	Timeline	Raw material	Status
Shell and Choren	Freiberg, Germany	—	Production to begin by end of 2009, 18 million liters/day capacity	Forest residues, straw, and waste wood	Building phase completed
Syntroleum, Tyson	Geismar, LA	150 (75 million gallons of fuel)	Plant completion by 2010	Feedstock oils, fats, and greases	Testing bio-synfining process

[20] www.greencarcongress.com/2008/06/syntroleum-tyso.html.
[21] www.accessmylibrary.com/coms2/summary_0286-34883260_ITM.
[22] www.verenium.com/pdf/Jennings_factsh.pdf.
[23] www.greencarcongress.com/2008/07/doe-to-provide.html.
[24] www.storaenso.com/CDAvgn/main/0,,1_EN-8276-17221-,00.html.
[25] www.greencarcongress.com/2007/03/neste_oil_and_s.html.
[26] www.greencarcongress.com/biomasstoliquids_btl/index.html.

Table A-3. Planned BtL Facilities

Stakeholders	Location	Investment ($ Million)	Timeline	Raw material	Status
DOE, Flambeau River Biofuels, and other investors	Wisconsin	40 (6 million gallons)	Announced July 2008	Wood chips	Small-scale facility
DOE, Verenium Biofuels Corporation, BP PLC	Jennings, LA	40 (DOE) 90 (BP)	Demo scale facility to be completed in late 2008	Sugarcane bagasse, agricultural byproducts, and waste wood	N/A
Neste Oil and Stora Enso	Finland	18.7	Demo-scale plant	Forest residues	N/A
Weyerhaeuser Company and Chevron Corporation JV formed Catchlight Energy, LLC	Federal Way, WA, and San Ramon, CA	—	Announced April 2007	Wood products, tall oil, and lignin	Research and development

COAL-TO-LIQUIDS

CtL Emissions

Proponents of CtL point to processes to ameliorate its carbon emissions such as carbon capture and sequestration (CCS) or the use of a coal-biomass mixture that could bring the life-cycle emissions below those of conventional petroleum diesel. However, most experts agree that CtL results in greater CO_2 emissions than petroleum, even if CCS is used**.** Life-cycle GHG emissions from CtL—which include all emissions from “coal mine” to “vehicle wheel”—are nearly twice as high as petroleum alternatives.[27]

Planned CtL Facilities

CONSOL Energy, Inc., the nation’s largest producer of bituminous coal, and Synthesis Energy Systems, Inc., a global industrial gasification company, intend to develop a coal gasification and liquefaction plant in West Virginia. Their joint venture is named Northern Appalachia Fuel, LLC, will cost an estimated $800 million, and will produce as much as 100 million gallons of gasoline per year.[28]

Rentech, using its own F-T CtL technology, plans to build a commercial-scale plant in Mississippi, just outside of Natchez. The facility will be built in two

[27] www.wri.org/stories/2007/05/coal-liquids-climate-change-and-energy-security.
[28] www.statejournal.com/story.cfm?func=viewstory&storyid=41949&catid=160.

phases. Phase one is to be completed in 2011 and will produce 1,600 b/d. Phase two is targeted to produce 28,000 b/d.[29]

Sasol is planning to build another CtL plant in South Africa. This project is known as the Mafutha project. Preliminary estimates are that Mafutha will be able to produce 80,000 b/d.[30] This plant is located close to a mine that could produce 20 million tons of coal a year.[31]

Sasol is looking into projects in China as well. The company is planning on constructing two CtL plants in China scheduled to begin operating as early as 2012. These 80,000 b/d capacity plants will both be built in Shaanxi province. The plants combined will cost upwards of $10 billion.[32]

Headwaters Incorporated announced in April 2007 that it is planning a coal-based liquid fuels refinery expected to use low-rank coals from the Philippines. This hybrid CtL plant is expected to be self-sufficient in electric power and will utilize an integrated design to take advantage of two different coal liquefaction approaches, direct and indirect, to produce 60,000 b/d.[33]

Table A-4 summarizes planned CtL facilities.

Table A-4. Planned Coal-to-Liquid F-T Operations

Stakeholders	Location	Investment	Timeline	Status
CONSOL and SES JV	West Virginia	$800 million	None given, announced August 2008	Deep saline aquifer carbon sequestration planned
Rentech	Natchez, MS	$48 million	1,600 b/d by 2011; 28,000 b/d at full scale in the future	Will be a full scale commercial operation
Sasol, Project Mafutha	South Africa	N/A	To be completed in 2015–17	Pre-feasibility stage
Sasol	China	$10 billion	Two plants tentatively planned for 2012 completion	Techno-economic viability studies
Headwaters and Bataan Petrochemcial	Philippines	N/A	To be completed late 2008	

29 www.greencarcongress.com/2007/12/rentech-switche.html.

30 www.miningweekly.com/article.php?a_id=142613.

31 www.busrep.co.za/index.php?fArticleId=4606521&fSectionId=566&fSetId=662.

32 www.platts.com/Coal/Resources/News%20Features/ctl/sasolchina.xml.

33 www.azom.com/News.asp?NewsID=8248.

DESC CONTRACTS FOR F-T FUEL

Syntroleum announced in 2006 that it had signed a contract to deliver 100,000 gallons of F-T alternative fuel to DoD. Syntroleum will provide the initial fuel for evaluation as part of a larger program aimed at domestic manufacture and supply of synthetic aviation fuels from F-T plants. The government is seeking up to 200 million gallons of alternative synthetic aviation fuel in 2008.

Syntroleum has worked with the U.S. Air Force to develop a synthetic jet fuel to reduce the service's dependence on conventional petroleum. In August 2007, the B-52H was certified to use a blend of synthetic and conventional fuel, marking the end of the initial phase of the program. The Air Force will use the test protocols developed during the program to certify the C-17 Globemaster III and then the B-1B in the use of the blended fuel. It contracted with Shell Oil Company for an additional 315,000 gallons for delivery in 2007. The Air Force intends to test and certify every airframe in its inventory to use the fuel by 2011.

Section 526 does not prohibit government purchase of F-T fuels for research purposes, even if they are higher in life-cycle GHGs than conventional fuels. However, because of 526, the source used to produce such fuels will be an important consideration because that largely will determine the life-cycle GHGs that result. For now, DESC apparently will not be able to purchase F-T fuels produced using coal as the base resource, but will be able to do so if biomass or natural gas is the source of choice.

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14. ABSTRACT
Section 526 of the Energy Independence and Security Act of 2007 (EISA) limits federal agencies with respect to the purchase of petroleum products derived from unconventional or alternative fuel sources whose life-cycle greenhouse gas emissions exceed those from conventional crude oil. The Defense Energy Support Center (DESC), as the principal purchaser of petroleum products for the U.S. military, wanted to examine the impacts of section 526 on its domestic bulk purchases of military fuels, specifically those that might be derived from Canadian oil sands recovered crude (COSRC). The study looked at current and planned COSRC shipments and refinery production equipment to estimate the potential use of COSRC by DESC suppliers. In conclusion, if DESC was forced to purchase bulk oil product containing only minimal quantities of COSRC, it may have to require some of its suppliers to isolate non-COSRC oil and product refined from it. This would likely result in fewer suppliers than otherwise and increased costs of supply to DESC.

15. SUBJECT TERMS
Canadian oil sands; EISA2007 Section 526; U.S. petroleum supplies; Defense Energy Support Center; military fuels; U.S. refining capacity.

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